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Environmental Impact Assessment Guidelines for New Source Coal Gasification Facilities

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16. ABSTRACT

This report provides guidance for evaluating the environmental impacts of proposed new source coal gasification facilities. Because EPA has not yet issued new source performance standards for the coal gasification industry, the guidelines are published in interim final form. The guidelines are intended to assist in the identification of potential environmental impacts, and the information requirements for evaluating such impacts, in documents prepared under the National Environmental Policy Act.

The report includes guidance on (1) identification of potential wastewater effluents, air emissions and solid wastes from coal gasification facilities, (2) assessment of the impacts of such residuals on the quality of the environment, (3) state-of-the-art technology for in-process and end-of-process control of waste streams, (4) evaluation of alternatives, and (5) environmental regulations that apply to the industry. In addition, the guidelines include an "overview" chapter that gives a general description of the coal gasification industry, significant problems associated with it, and recent trends in location, raw materials, processes, pollution control, and the demand for industry output.

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AUGUST, 1980

INTERIM FINAL ENVIRONMENTAL IMPACT ASSESSMENT GUIDELINES FOR NEW SOURCE COAL GASIFICATION FACILITIES

EPA TASK OFFICER: JOHN W. MEAGHER

OFFICE OF ENVIRONMENTAL REVIEW
U.S. ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

1A

PREFACE

This document is one of a series of industry specific environmental impact assessment guidelines being developed by the Office of Environmental Review for use in EPA's program for applying the National Environmental Policy Act (NEPA) to EPA's issuance of New Source NPDES permits. It is intended to be used in conjunction with Environmental Impact Assessment Guidelines for Selected New Source Industries, an OER publication that includes a description of impacts common to most industrial new sources.

The requirement for federal agencies to assess the environmental impacts of their proposed actions is included in Section 102 of NEPA. The stipulation that EPA's issuance of a New Source NPDES permit is an action subject to NEPA in Section 511(c)(1) of the Clean Water Act of 1977. EPA's regulations for preparation of Environmental Impact Statements are in Part 6 of Title 40 of the Code of Federal Regulations; New Source requirements are in Subpart F of that Part.

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INTRODUCTION

The Clean Water Act requires that EPA establish standards of performance for categories of new source industrial wastewater discharges. Before the discharge of any pollutant to the navigable waters of the United States from a new source in an industrial category for which performance standards have been proposed, a new source National Pollutant Discharge Elimination System (NPDES) permit must be obtained from either EPA or the State (whichever is the administering authority for the State in which the discharge is proposed). The Clean Water Act also requires that the issuance of a permit by EPA for a new source discharge be subject to the National Environmental Policy Act (NEPA), which may require preparation of an Environmental Impact Statement (EIS) on the new source. The procedure established by EPA regulations (40 CFR 6 Subpart F) for applying NEPA to the issuance of new source NPDES permits may require preparation of an Environmental Information Document (EID) by the permit applicant. Each EID is submitted to EPA and reviewed to determine if there are potentially significant effects on the quality of the human environment resulting from construction and operation of the new source. If there are, EPA publishes an EIS on the action of issuing the permit.

The purpose of these guidelines is to provide industry-specific guidance to EPA personnel responsible for determining the scope and content of EID's and for reviewing them after submission to EPA. It is to serve as supplementary information to EPA's previously published document, Environmental Impact Assessment Guidelines for Selected New Source Industries, which includes the general format for an EID and those impact assessment considerations common to all or most industries. Both that document and these guidelines should be used for development of an EID for a new source coal gasification facility.

EPA had not yet issued new source performance standards for coal gasification facilities at the time of publication of these guidelines. Until such standards are proposed, EPA will not have a statutory requirement to prepare EIS's on coal gasification facilities. This document is being published in interim final form to familiarize EPA staff with the industry in anticipation of the new source performance standards and because the information herein may be useful in other EPA NEPA activities, such as scoping and EIS review. The guidelines will be revised and published in a final form when the new source performance standards for coal gasification facilities are issued.

These guidelines provide the reader with an indication of the nature of the potential impacts on the environment and the surrounding region from construction and operation of a coal gasification plant. In this capacity, the volume is intended to assist EPA personnel in the identification of those impact areas that should be addressed in an EID. In addition, the guidelines present (in Chapter I) a description of the industry, its principal processes, environmental problems, and recent trends in location, raw materials, processes, pollution control and the demand for industry output. This "Overview of the Industry" is included to familiarize EPA staff with existing conditions in the industry.

Although this document may be transmitted to an applicant for informational purposes, it should not be construed as representing the procedural requirements for obtaining an NPDES permit or as representing the applicant's total responsibilities relating to the new source EIS program. In addition, the content of an EID for a specific new source applicant is determined by EPA in accordance with Section 6.604(b) of Title 40 of the Code of Federal Regulations and this document does not supersede any directive received by the applicant from EPA's official responsible for implementing that regulation.

The guidelines are divided into six sections. Section I is the "Overview of the Industry," described above. Section II, "Impact Identification," discusses process-related wastes and the impacts that may occur during construction and operation of the facility. Section III, "Pollution Control," describes the technology for controlling environmental impacts. Section IV discusses other impacts that can be mitigated through design considerations and proper site and facility planning. Section V, "Evaluation of Alternatives," discusses the consideration and impact assessment of possible alternatives to the proposed action. Section VI, describes regulations other than pollution control that apply to the industry.

I. OVERVIEW OF THE INDUSTRY

I.A. SUBCATEGORIZATION

This industry has not been subcategorized for the purpose of issuing effluent guidelines. However a variety of parameters (i.e., pressure, bed type) can be used to categorize various processes currently under development.

The coal gasification process should be viewed as the central step in a complex refinerylike operation that can convert coal to a variety of products, including pipeline gas or chemicals such as methanol or ammonia.

The coal gasification stage, itself, may produce different mixtures of three combustible gases including: hydrogen (H_2), carbon monoxide (CO), and methane (CH_4) in varying concentrations, depending on the process used. The simplest processes involve the direct contact of air and steam with coal at elevated temperatures and atmospheric pressure. This produces a gas mixture with a low heat content that ranges from 3,721,754 to 7,443,503 joules per cubic meter (J/m^3) (100 to 200 Btu per standard cubic foot). Substitution of oxygen for air will elevate the heat content to between 9,304,385 and 11,165,254 J/m^3 (250-300 Btu/scf). Both of these process routes produce what is termed low Btu gas. As the pressure of the reactor is raised, the formation of methane (CH_4) is favored and the energy content of the resulting gas is increased. Coal gasification processes which use extremely high pressures (1,000 psi), can obtain gas with a heat content ranging from 24,191,384 to 26,052,260 J/m^3 (650 to 700 Btu/scf). Such processes are termed medium Btu processes. End products from medium Btu gasifiers (i.e., CO, H_2, and CH_4) can be used for industrial energy production. More commonly, however, products are used in a complex set of chemical reactions, similar to those found in a refinery, in order to produce pipeline quality or high Btu gas with a heat content of 35,728,813 J/m^3 or higher (960 Btu/scf or higher) or other products such as methanol or ammonia.

A list of low and medium Btu coal gasification processes is presented in Table 1 and detailed descriptions of the processes are contained in Howard-Smith (1976).

In addition to the difference in the quality (heat content) of product gas, coal gasification processes also may differ in the type of reactor vessel. Three general categories are:

- Gasifier
- Hydrogasifier
- Devolatilizer

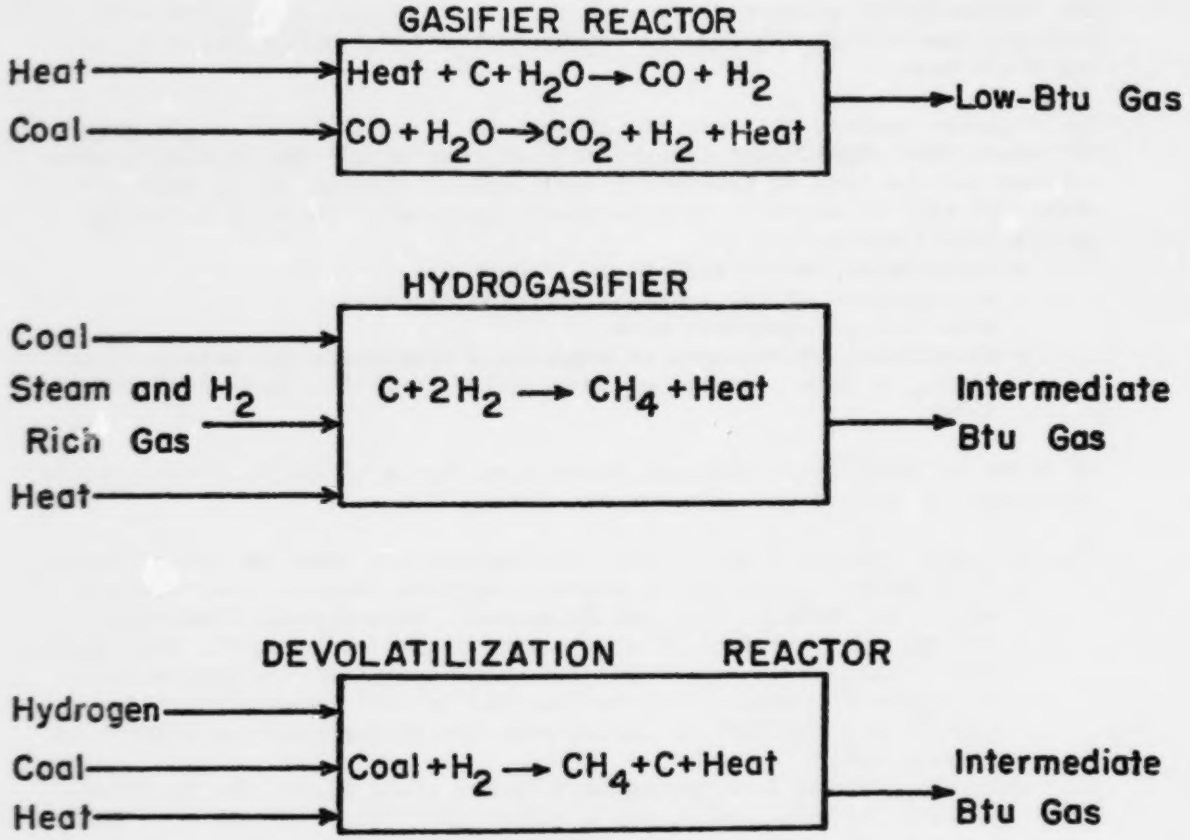
The reactions for each are shown in simplified form in Figure 1. Gasification systems employ one or more of these reactor types.

As shown in Figure 1, the gasifier reactor produces gas through the steam-carbon reaction (heat + $C + H_2O \rightarrow CO + H_2$). The major differences in gasifier reactor systems are in the method (direct or indirect) of providing heat.

In the hydrogasifier reactor, methane is produced by reacting hydrogen with coal or char under pressure ($C + 2H_2 \rightarrow CH_4$ + heat). Although systems of this type differ in the method of supplying hydrogen, all hydrogasifiers produce up to twice as much methane as gasifiers or devolatilizers of comparable capacity.

Table 1. Low and medium Btu coal gasification processes

Agglomerating ash
Avco arc coal process
Babcock & Wilcox (DuPont)
CE entrained fuel process
Combined cycle (B&W)
Combined cycle (F-W)
Consol fixed bed
Electric arc
Fixed bed (Kellogg)
GRD gasification
Gegas
HRI fluidized bed
HRI gasification (Squires)
ICI moving burden
IFE two-stage
IGI two-stage
In-situ gasification (also known as "underground gasification")
Kerpely producer
Koppers-Totzek
Laser irradiation pyrolysis
Lurgi
Marischka
Molten-salt
Multiple fluidized bed
Otto Rummel slag bath (double shaft)
Panindco
Philadelphia & Reading
Pintsch Hillebrand
Power gas
Rapid high temperature
Riley-Morgan
Rockgas
Ruhrgas vortex
Rummel slag bath (single shaft)
Stirred fixed bed (also known as "Moras")
Texaco gasification
Thyssen Galocsy
Two-stage process (also known as "submerged coal combustion")
Two-step coal pyrolysis gasification
U-Gas


GASIFIER REACTOR
Heat
Coal
Heat + C + $H_2O \rightarrow CO + H_2$
$CO + H_2O \rightarrow CO_2 + H_2$ + Heat
Low-Btu Gas
HYDROGASIFIER
Coal
Steam and H_2 Rich Gas
Heat
$C + 2H_2 \rightarrow CH_4$ + Heat
Intermediate Btu Gas
DEVOLATILIZATION REACTOR
Hydrogen
Coal
Heat
Coal + $H_2 \rightarrow CH_4$ + C + Heat
Intermediate Btu Gas

Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC.

Figure 1. Principal coal gasification reactions and reactor types

The devolatilizer reactor decomposes large coal compounds. In this sytem, hydrogen reacts with the coal to produce methane and heat (coal + $H_2 \rightarrow CH_4 + C$ + heat).

Gasification systems also can be categorized on the basis of engineering features. Two significant features are whether or not the system is pressurized and the type of bed used. Gasification systems may be operated either at high pressure or at atmospheric pressure. The main advantages gained from pressurizing are:

- Improvement in the quality of product gas
- Maximization of the hydrogasification reaction
- Reduction of equipment size
- Elimination of the need to separately pressurize gas before introducing it into a pipeline (Interagency Synthetic Fuels Task Force 1974).

In terms of beds, there also are three basic types of gasification systems: fixed-bed, fluidized-bed, and entrained-bed.

The following descriptions of these bed systems are based on Corey (1974).

- Fixed-bed--In this system a grate supports lumps of coal through which the steam or hydrogen is passed. Conventional fixed-bed systems are incompatible with caking coals (coals which, when heated, pass through a plastic stage and cake or agglomerate into a mass). To expand the range of coals that can be used, some fixed-bed systems are modified to incorporate a rotating grate or stirrer to prevent caking.
- Fluidized-bed--This system uses finely sized coal. Gas is flowed through the coal, producing a lifting and "boiling" effect. The result is an expanded bed with more coal surface area to promote the chemical reactions. Fluidized-bed systems also have a limited capacity for operating with caking coals; consequently, these types of coals often are pretreated to destroy caking characteristics when the fluidized-bed system is used.
- Entrained-bed--This system also uses finely sized coal. The coal particles are transported in the gas (for example, steam and oxygen) prior to introduction into the reactor. The chemical reactions occur, and the product gases and ash are taken out separately. There are no limitations on the types of coal that can be used with the entrainment system.

The environmental assessment guidelines contained in this document focus on the Lurgi gasification process and associated clean up procedures such as tar removal and sulfur recovery. Some emphasis has been placed on the Lurgi process because more "hard" information is available. Nevertheless, many of the information and assessment techniques will apply to other coal gasification processes (Koppers-Totzek, Winkler, etc.). We also recognize that many permit applications may include other chemical processes as well as ancillary facilities such as an oxygen plant, coal mine, railroad spur, pipeline, or electric generating station; however, EID guidelines for most of these facilities will be contained in separate guidelines.

I.B. PROCESSES[1]

The gasification plant proper normally would include all process units necessary to produce pipeline quality gas from presized coal. Coal preparation and classification techniques common to the coal industry are utilized to prepare the coal. The main process area would consist of a gasification system composed of these six process units:

- Gasification
- Shift conversion
- Gas cooling
- Gas purification unit
- Methanation
- Gas compression and drying

and a byproduct recovery system composed of four process units:

- Gas liquor separation
- Pehnosolvan unit
- Ammonia recovery
- Sulfur recovery

The discussion that follows presents a summary description of these steps as well as brief but specific descriptions of the major low, intermediate, and high Btu processes for the gasification of coal. A block diagram of the process is shown in Figure 2.

I.B.1. Gasification Process Units

A variety of gasification processes are currently in operation or under development. The gasification process has already been described in Section I.A. and the details of various processes are discussed in Section I.B.3. and I.B.4. Figure 3 illustrates a typical gasifier (Lurgi in this case).

I.B.1.a. Shift Conversion. The amount of methane (the principal component of natural gas) in the crude gas from the gasification unit is low and further chemical conversion of the crude gas to increase the methane content is necessary. This conversion is performed in the crude gas shift and methanation units. The shift conversion unit is designed to produce the hydrogen (H_2) required to adjust the H_2:CO ratio for the methanation unit. This is accomplished through the "water gas shift" reaction carried out over a catalyst (usually an iron-chromium oxide compound) in the presence of steam as follows:

$$CO + H_2O \rightarrow CO_2 + H_2 + \text{heat}$$

Approximately 33% of the total crude gas is subject to shift conversion with the balance bypassed directly to the gas cooling unit. The proportions of the two gas streams are adjusted to achieve the desired H_2:CO ratio for methanation (usually about 3:1).

A series of processes are utilized to produce high Btu gas. These are included for completion.

I.B.1.b. Gas Cooling. The gas cooling unit is designed to cool the raw gas from gasification and shift conversion and to remove the heavier hydrocarbons and unreacted steam before low temperature purification. The cooling scheme is arranged to recover and use as much of the process heat as practical;

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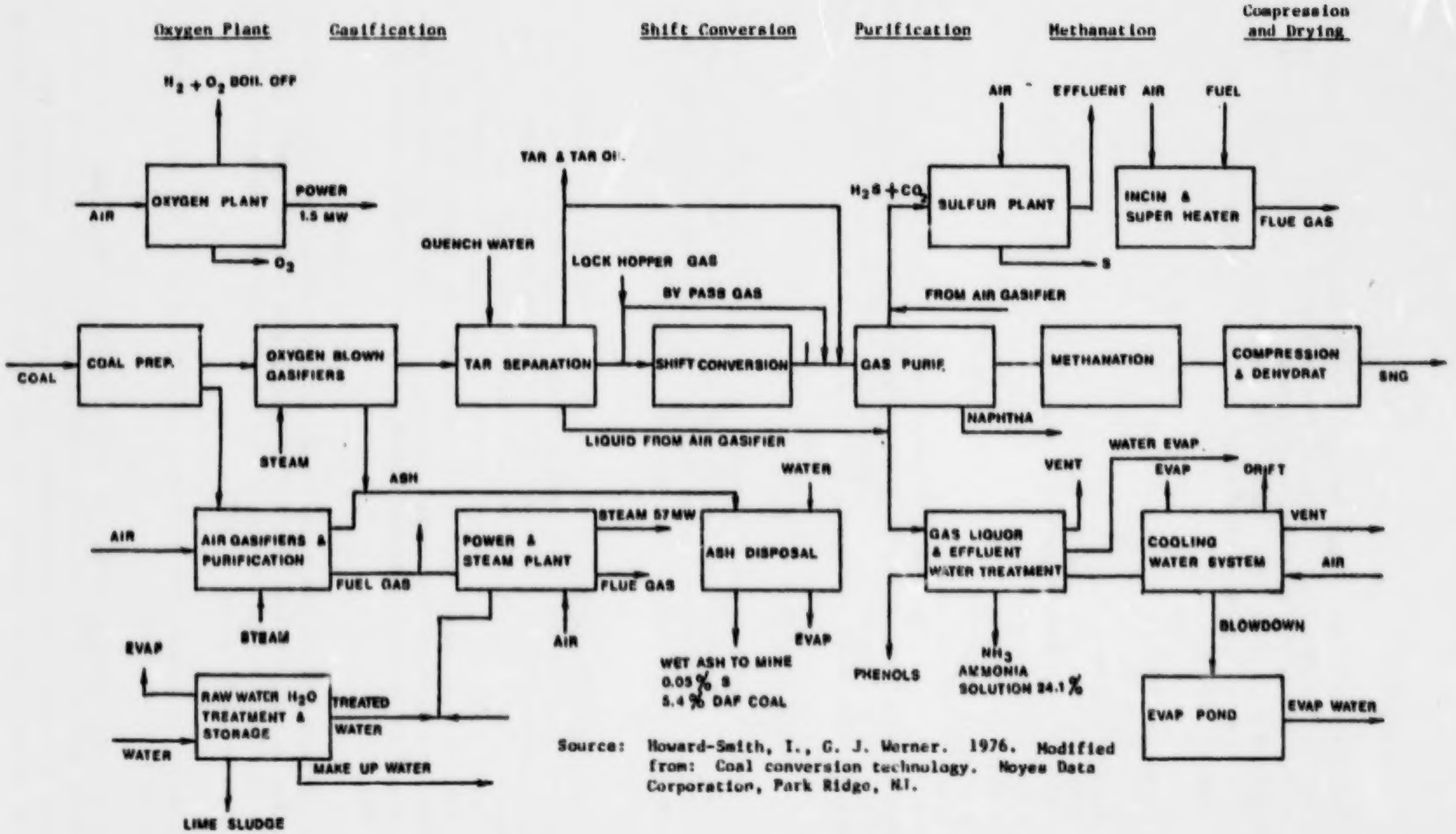
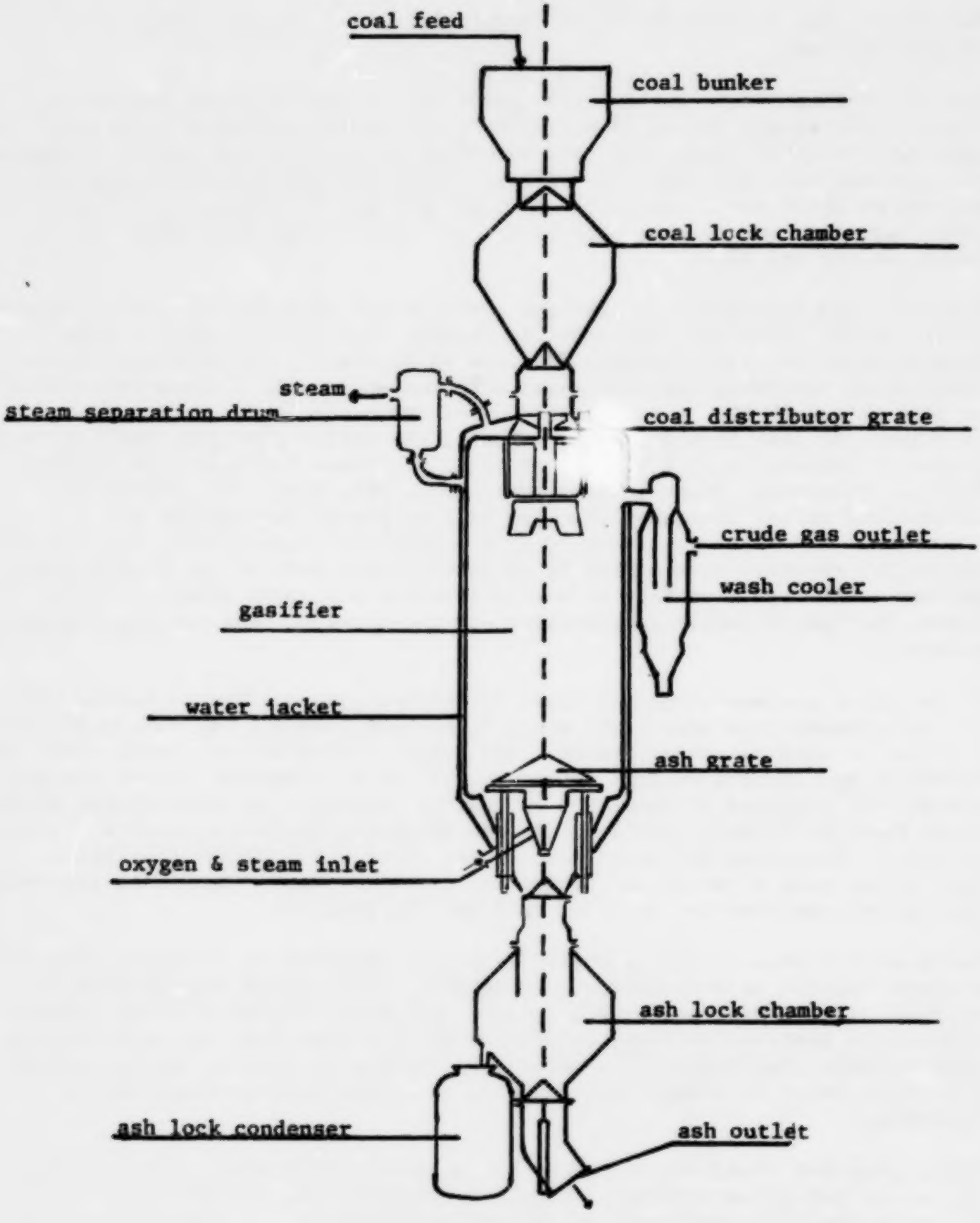
[1] This section is based largely on technical information presented in University of Oklahoma (1975) and US-DOI (1978).


Oxygen Plant
Gasification
Shift Conversion
Purification
Methanation
Compression and Drying
H2 + O2 BOIL OFF
AIR
OXYGEN PLANT
POWER 1.5 MW
O2
TAR & TAR OIL
QUENCH WATER
LOCK HOPPER GAS
BY PASS GAS
H2S + CO2
SULFUR PLANT
S
AIR
EFFLUENT
AIR
FUEL
INCIN & SUPER HEATER
FLUE GAS
FROM AIR GASIFIER
COAL
COAL PREP.
OXYGEN BLOWN GASIFIERS
TAR SEPARATION
SHIFT CONVERSION
GAS PURIF.
METHANATION
COMPRESSION & DEHYDRAT
SNG
NAPHTHA
STEAM
LIQUID FROM AIR GASIFIER
ASH
WATER
VENT
WATER EVAP
EVAP
DRIFT
AIR
AIR GASIFIERS & PURIFICATION
FUEL GAS
POWER & STEAM PLANT
STEAM 57MW
FLUE GAS
ASH DISPOSAL
GAS LIQUOR & EFFLUENT WATER TREATMENT
COOLING WATER SYSTEM
VENT
AIR
STEAM
AIR
WET ASH TO MINE 0.05% S 5.4% DAF COAL
EVAP
PHENOLS
NH3 AMMONIA SOLUTION 24.1%
BLOWDOWN
EVAP
RAW WATER H2O TREATMENT & STORAGE
TREATED WATER
WATER
MAKE UP WATER
LIME SLUDGE
EVAP POND
EVAP WATER

Source: Howard-Smith, I., G. J. Werner. 1976. Modified from: Coal conversion technology. Noyes Data Corporation, Park Ridge, NJ.

Figure 2. Block flow diagram for a typical (275mm SCF/SD capacity) coal gasification plant


coal feed
coal bunker
coal lock chamber
steam
steam separation drum
coal distributor grate
crude gas outlet
wash cooler
gasifier
water jacket
ash grate
oxygen & steam inlet
ash lock chamber
ash lock condenser
ash outlet

Source: U.S. Department of the Interior, Upper Missouri Region. 1978. Final environmental impact statement, ANG Coal Gasification Company North Dakota Project. FES78-1.

Figure 3. Lurgi pressure gasifier

further cooling is done in wet and dry coolers, depending on water availability and cost.

The gas cooling in the gasification plant may be done in three parallel stages. Two stages for cooling the crude gas bypass the shift conversion area and the other stage cools the converted gas. Converted gas is compressed and combined with the crude gas stream. The mixed gas stream, having a predetermined H_2:CO ratio, is conveyed to the gas purification unit. The condensate from gas cooling goes to the gas liquor separation unit for recovery of tar and oil.

I.B.1.c. Gas Purification. The gas purification unit removes carbon dioxide (CO_2), sulfur compounds, and other impurities from the raw gas. A flow diagram of a Rectisol process is shown in Figure 4. The Rectisol process operates by scrubbing the acid gases with methanol. The gas can be purified to less than 1.5% CO_2 by volume and sulfur compounds (H_2S and COS) removed to a level of less than 1 ppm (by volume); the sulfur free gas then can be passed to methanation. A variety of other processes including the Selexol, Purisol, Estasduan, Fluor Solvent, MEA, MDEA, DEA, DIPA, DGA, Benfield, Sulfinol and Amisol processes also are used to purify the raw gases.

The sulfur recovery system also is an interrelated part of any purification process. Although a variety of sulfur recovery processes exists, the two oldest and best established processes are the Claus process and the Stretford process.

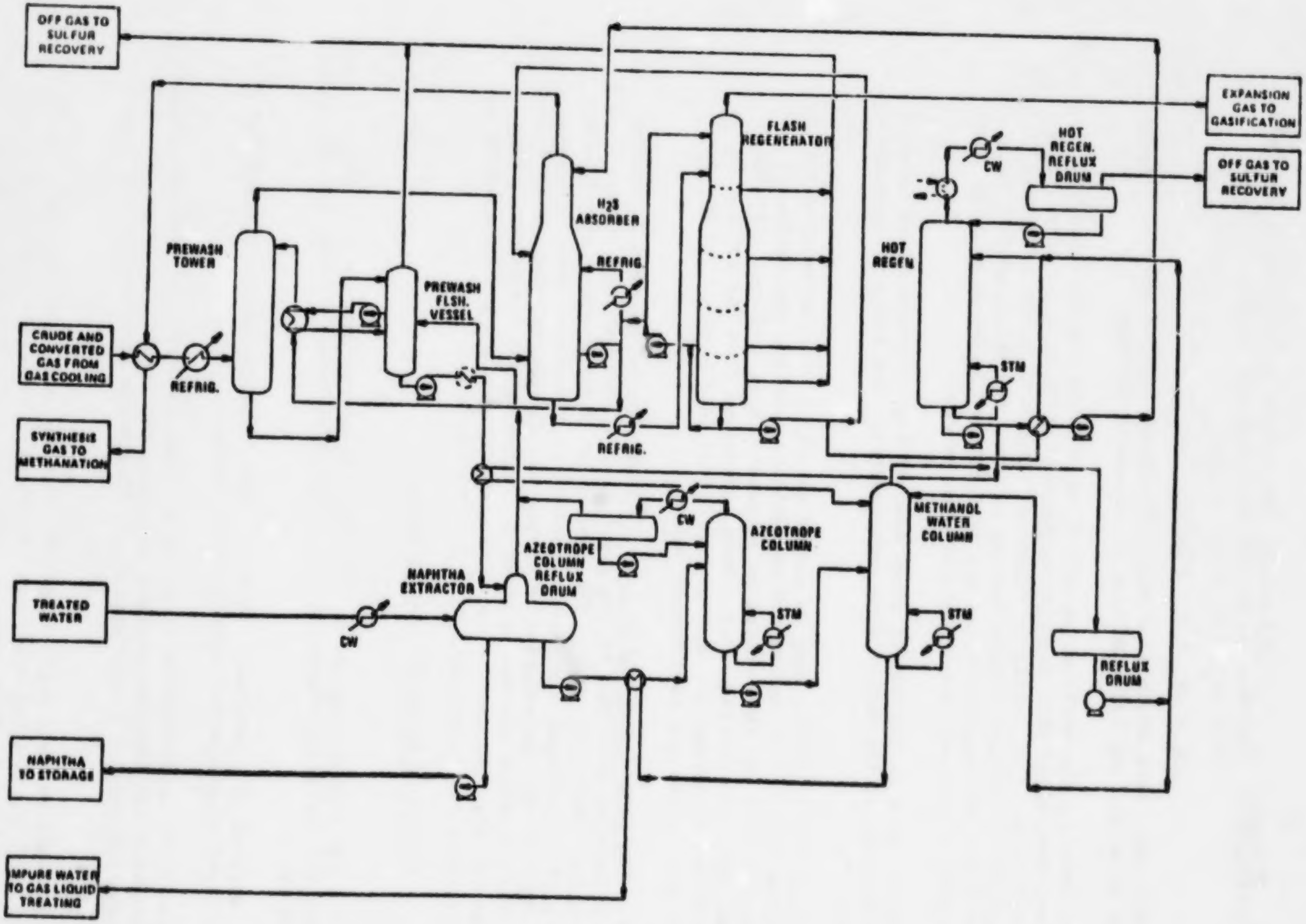
In the Claus process about one-third of the hydrogen sulfide is burned with air in a pressurized boiler and most of the heat generated by the exothermic reaction is used to produce steam. The sulfur oxides stream reacts with the remaining H_2S to form sulfur. After the sulfur is condensed out of the gas stream, the reaction is completed by heating the gases to temperatures which range from 204°C-260°C (400°F-500°F) and passing them over a bauxite alumina catalyst. Operating pressures usually are about 4.8-7.2kg/m^2 (14-21psi). This latter step normally is carried out in two or more stages with interstage cooling and condensation in order to favor the reaction.

The Stretford process uses a sodium carbonate solution which reacts with the hydrogen sulfide to form sodium hydrosulfide. The sodium hydrosulfide is oxidized to elemental sulfur with sodium vanadate. The vanadium is oxidized back to the pentavalent state by blowing the solution with air using sodium anthraquinone disulfonate as a catalyst. The finely divided sulfur appears as a froth which is skimmed off, washed, and dried by centrifugation or filtration.

Other processes available to reduce H_2S concentrations are:

- Hot potassium carbonate scrubbing (reduction to 10 ppm)
- Rectisol-solvent based scrubbing (reduction to 0.1 ppm)
- Selexol-solvent based scrubbing (reduction to 0.1 ppm)
- Sulfinol-amine scrubbing (reduction to 1 ppm)
- MEA-monoethanolamine scrubbing (reduction to 1 ppm)
- DIPA-disopropanolamine scrubbing (reduction to 1 ppm)

In these processes, traces of SO_2, COS, CS_2 and CO_2 are found in the tail gases. Tail gas processes which can reduce sulfur compounds to as low as 0.1 ppm include Beavon, Clean Air, Sulfreen, Shell Copper Oxide, SCOT, Wellman-Lord and Chiyoda Thoroughbred 101.


OFF GAS TO SULFUR RECOVERY
EXPANSION GAS TO GASIFICATION
FLASH REGENERATOR
HOT REGEN. REFLUX DRUM
CW
OFF GAS TO SULFUR RECOVERY
H_2S ABSORBER
PREWASH TOWER
HOT REGEN
REFRIG.
PREWASH FLSH. VESSEL
CRUDE AND CONVERTED GAS FROM GAS COOLING
STM
REFRIG.
SYNTHESIS GAS TO METHANATION
REFRIG.
CW
METHANOL WATER COLUMN
AZEOTROPE COLUMN
AZEOTROPE COLUMN REFLUX DRUM
NAPHTHA EXTRACTOR
TREATED WATER
CW
STM
STM
REFLUX DRUM
NAPHTHA TO STORAGE
IMPURE WATER TO GAS LIQUID TREATING

Source: U.S. Department of the Interior, Upper Missouri Region. 1978. Final environmental impact statement, ANG Coal Gasification Company North Dakota Project. FES78-1.

Figure 4. Flow diagram of the Rectisol purification process

I.B.1.d. Methanation. The methanation unit converts the low Btu synthetic gas to methane-rich high Btu gas by the following exothermic reactions:

$$CO + 3H_2 \rightarrow CH_4 + H_2O + \text{heat}$$

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O + \text{heat}$$

Other minor reactions which also could take place are the hydrogeneration of ethylene to ethane and hydrocracking of ethane to methane.

Feed gas entering the methanation unit from each gas purification unit first is heated and then mixed with recycled methanated effluent gas before being methanated in parallel catalytic reactors. The feed gas is sometimes diluted with methanated effluent before heating to limit the temperature rise across the reactors. The reactors often are designed as fixed-bed downflow units which employ a pelleted reduced nickel-type catalyst.

The reaction heat is removed by generation of high pressure steam in waste heat exchangers at the outlet from each reactor. The steam is recycled to the gasifier.

Gas leaving the synthesis loop is passed through a cleanup reactor (final methanation reactor) to accomplish essentially complete conversion of carbon monoxide (CO) and then cooled by successive heat exchange with fresh feed gas, air, and cooling water. Water condensed from the gas may be separated and forwarded for recovery as boiler feed water. The net produce then is sent to the gas compression unit.

I.B.1.e. Gas Compression and Drying. This system is designed to deliver the synthetic natural gas (SNG) to the pipeline at a pressure that ranges from 56-105 kg/cm^2 (800-1,500 psi). The product gas compression system usually consists of centrifugal compressors, driven by condensing steam turbines. The product is dry, in addition to having the CO_2 content reduced to below 1.5%. Final product gas now is ready for metering and discharge to the pipeline for distribution. Final drying of the product gas to pipeline gas specifications is accomplished by a dehydration unit.

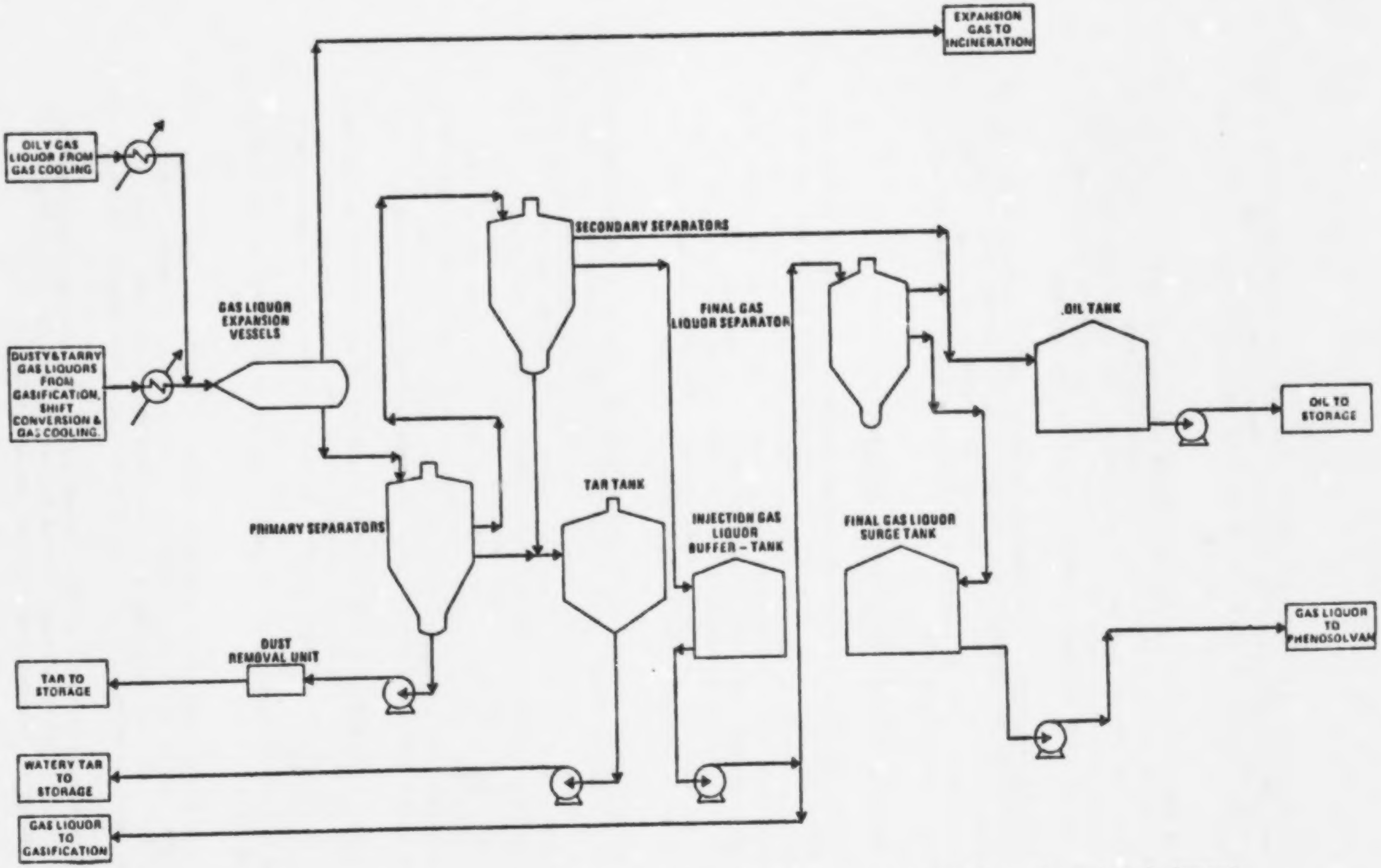
I.B.2. Byproduct Recovery Process Units

I.B.2.a. Gas liquor separation. The gas liquor may contain tar, tar oil, naphtha, and dissolved compounds such as phenols, ammonia, CO_2, and hydrogen sulfide (H_2S).

Tar is defined as a heavier-than-water organic liquid phase, whereas tar oil is the lighter-than water organic liquid phase.

The gas liquor separation is designed to clean up tarry and oily gas liquors by separating the incoming streams into tar, tar oil, recycled gas liquor, and clarified aqueous liquor streams by fractional condensation and liquid settling.

The gas liquor streams which originate from the gasification, shift conversion, and gas cooling units are cooled, combined, and reduced in pressure. The entrained gases, which consist primarily of CO_2 but with traces of CH_4, CO, NH_3, and H_2S, are released and passed through a water scrubber for recovery of ammonia and then move to a low pressure flare for incineration. A flow diagram of the process is shown in Figure 5.


OILY GAS LIQUOR FROM GAS COOLING
DUSTY & TARRY GAS LIQUORS FROM GASIFICATION, SHIFT CONVERSION & GAS COOLING
GAS LIQUOR EXPANSION VESSELS
EXPANSION GAS TO INCINERATION
PRIMARY SEPARATORS
SECONDARY SEPARATORS
FINAL GAS LIQUOR SEPARATOR
OIL TANK
OIL TO STORAGE
TAR TANK
INJECTION GAS LIQUOR BUFFER - TANK
FINAL GAS LIQUOR SURGE TANK
GAS LIQUOR TO PHENOSOLVAN
DUST REMOVAL UNIT
TAR TO STORAGE
WATERY TAR TO STORAGE
GAS LIQUOR TO GASIFICATION

Source: U.S. Department of the Interior, Upper Missouri Region. 1978. Final environmental impact statement, ANG Coal Gasification Company North Dakota Project. FES78-1.

Figure 5. General flow diagram of gas liquor separation process

I.B.2.b. Phenosolvan. The process water from the gas liquor separation unit, which is usually contaminated with phenols, ammonia, H_2S, and CO_2 is treated in the Phenosolvan unit for removal of phenols before it is transferred to the ammonia recovery system.

The incoming process water is passed through extractors where an organic solvent is used to extract phenols. The organic solvent is distilled and separated from the phenol and may be recycled to the extractors for reuse. The crude phenol byproduct may be recovered and transferred to storage for subsequent use as part of the byproducts feed to the boilers.

I.B.2.c. Ammonia Recovery. The ammonia recovery unit normally involves the selective absorption of ammonia from the gas liquor leaving the phenosolvan unit. A water solution of NH_3, CO_2 and H_2S are removed by steam distillation at the liquid phase, then an ammonium phosphate solution is used to selectively absorb ammonia (see Figure 6).

I.B.3. Specific Low Btu Gasification Processes

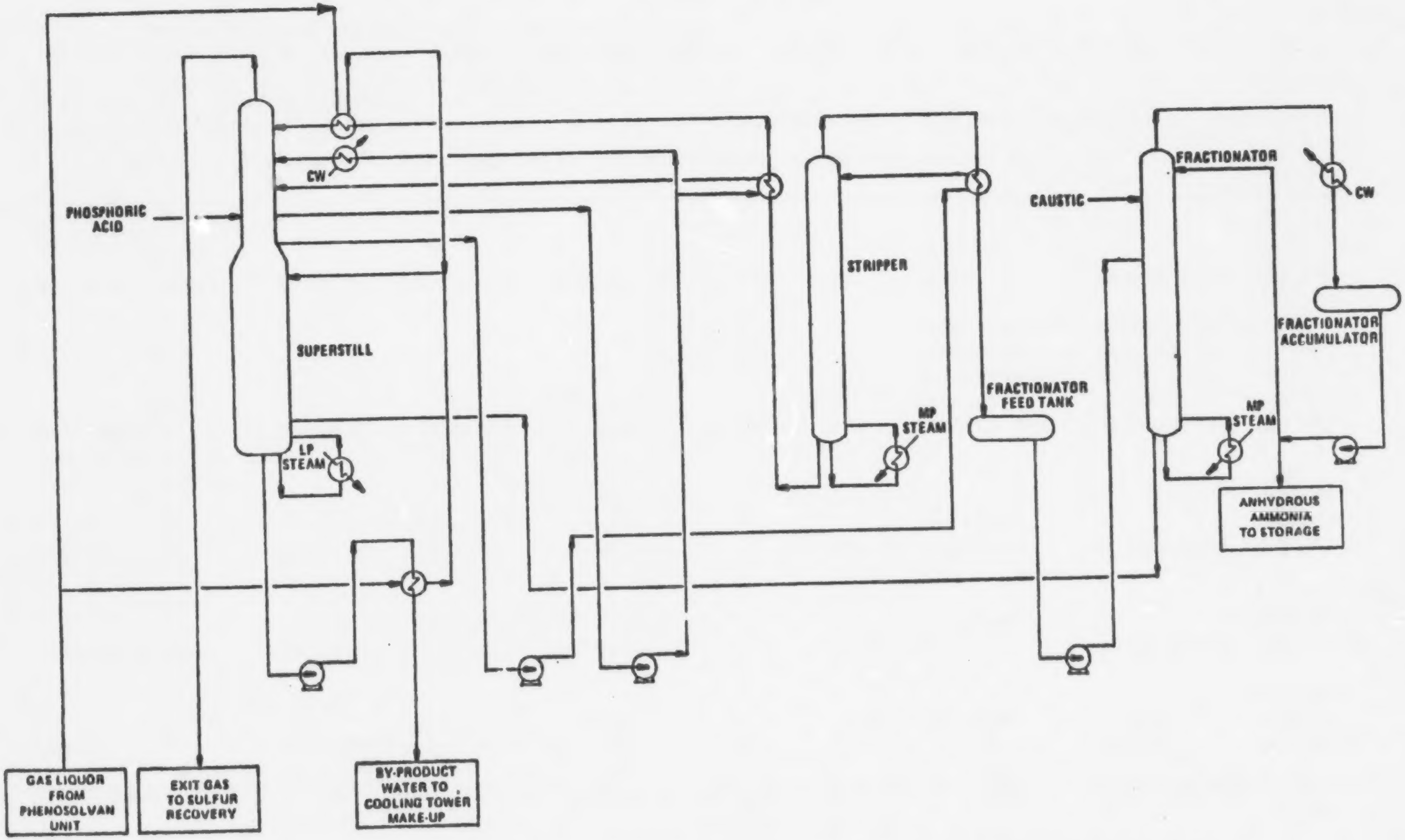
The major characteristics of five processes designed to produce either low or intermediate Btu gas from coal are discussed briefly below and are summarized in Table 2, and their status shown in Table 3. Two of these, Lurgi and Koppers-Totzek, are used commercially; the others are in the pilot plant stage. A large number of other processes (with, for example, different combinations of bed types, pressure levels, and oxygen sources) have been proposed or are in early stages of development. The five technologies described below illustrate the current state of the art.

I.B.3.a. Lurgi Low/Intermediate Btu Gasification. There is no pretreatment (except sizing) in the Lurgi process and only noncaking coals can be used. As shown in Figure 7, pulverized coal is introduced into a pressurized reactor vessel through a lock hopper. The coal passes down and is distributed onto a rotating grate. Steam and oxygen are introduced below the grate. All the coal is combusted, leaving only ash which is allowed to fall through the grate. Product gas from the combustion zone above the grate leaves the reactor at 700-811°K (800-1,000°F). To produce 250 billion Btu's per day, 27 to 33 gasifiers of 3.9 meters (13 ft.) I.D. would be required. Materials balance and water balance for the Lurgi process are shown in Table 4.

I.B.3.b. Koppers-Totzek. In the Koppers-Totzek process, finely ground coal after thermal drying is mixed with oxygen and steam, then pumped into an atmospheric-pressure vessel (Figure 8). Because of the low pressures used and the entrained flow of the materials injected, a complex and potentially troublesome system of hoppers is avoided. Two or four injection or burner heads may be used.

Combustion occurs at high temperatures (1644°C (3,000°F)) in the center of the reactor vessel and the product gas exits upwards through a central vertical outlet. Molten slag exits at the bottom. A typical large gasifier is about 3 meters (10 ft.) in diameter and 7.6 meters (25 ft.) long.

A Koppers-Totzek reactor will produce about twice the gas per unit reactor volume of a Lurgi reactor because of its higher throughput capabilities (National Academy of Engineering/National Research Council 1973).


GAS LIQUOR FROM PHENOSOLVAN UNIT
EXIT GAS TO SULFUR RECOVERY
BY-PRODUCT WATER TO COOLING TOWER MAKE-UP
PHOSPHORIC ACID
CW
SUPERSTILL
LP STEAM
STRIPPER
MP STEAM
FRACTIONATOR FEED TANK
CAUSTIC
FRACTIONATOR
CW
FRACTIONATOR ACCUMULATOR
MP STEAM
ANHYDROUS AMMONIA TO STORAGE

Source: U.S. Department of the Interior, Upper Missouri Region. 1978. Final environmental impact statement, ANG Coal Gasification Company North Dakota Project. FES78-1.

Figure 6. Flow diagram of an ammonia recovery process

Table 2. Selected design features of five low and intermediate Btu gasification processes

Name	Reactor type	Bed type	Pressure	Hydrogen sources	Oxygen sources	Heat	Pretreatment	Coal input
Lurgi	Gasifier	Modified fixed	300-450 lbs/in^2	Steam	Air/ oxygen	Direct burning	Sizing	Noncaking 1/4x2", no fines
Koppers-Totzek	Gasifier	Extrained suspension	Atmospheric	Steam	Oxygen	Direct burning	Pulverizing	Caking or noncaking, pulverized[a]
BuMines[b]	Gasifier	Modified fixed	Atmospheric to 300 lbs/in^2	Steam	Air	Direct burning	Pulverizing	Caking or noncaking, coarse or fine
Westinghouse	Gasifier	Fluidized	200-300 lbs/in^2	Steam	Air	Direct and internal exothermic reactions in desulfurizer	Pulverizing drying, integrated devolatiles/ desulfurizers	Caking or noncaking, pulverized
Ash agglomerating	Gasifier	Fluidized	Pressurized	Steam	Air	Direct burning	Pulverizing	Caking or noncaking, pulverized

[a] Pulverized means crushed so that 70%-80% of the coal passes a 200-mesh screen (0.003").

[b] The BuMines process listed here is often identified as two processes. The only difference between the two is that one is pressurized.

Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-0025-4, Washington DC.

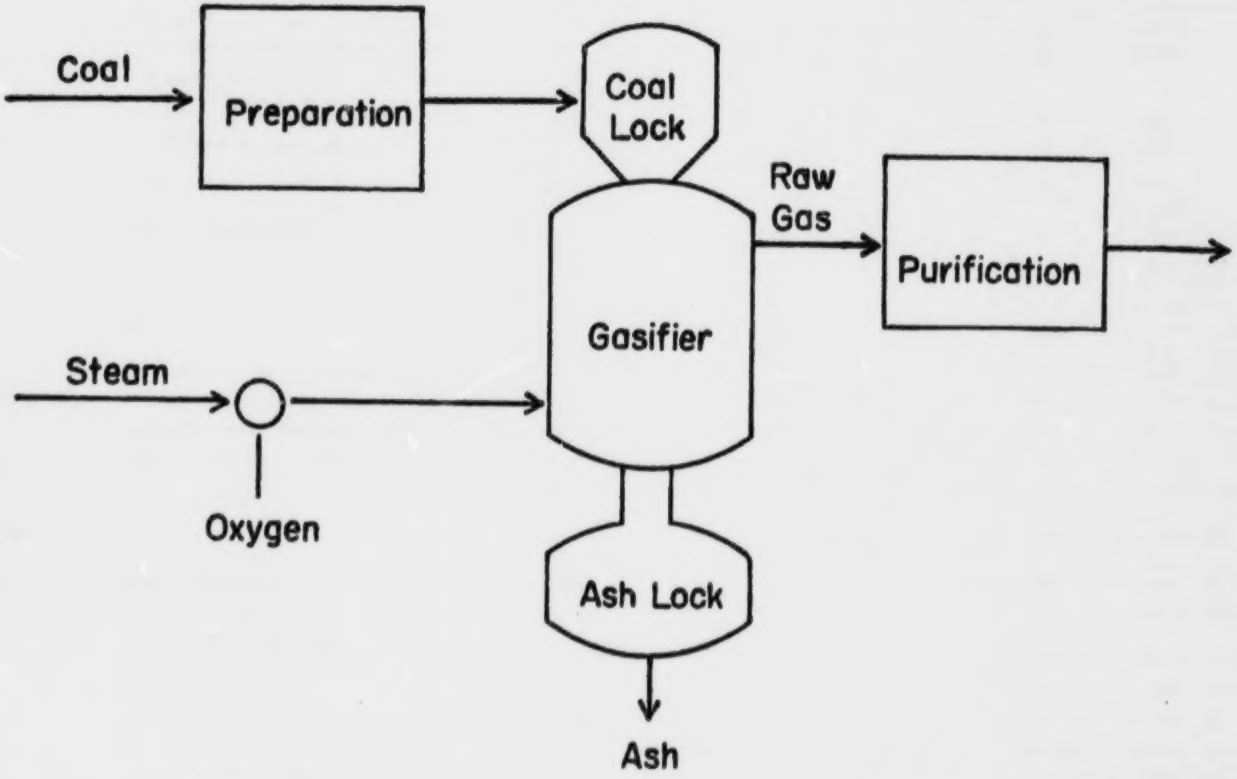
Table 3. U.S. AND FOREIGN STATUS OF LOW/MEDIUM-BTU GASIFICATION TECHNOLOGY

Gasifier	Licensor/developer	No. of gasifiers currently operating (no. of gasifiers built) Low-Btu gas	Medium-Btu gas	Synthesis gas	Location	Scale
Lurgi	Lurgi Mineralöltechnik GmbH	5	(39)	(22)	Foreign	Commercial
Wellman-Galusha	McDowell Wellman Engineering Co.	8(150)	-	-	US/Foreign	Commercial
Woodall-Duckman/ Gas Integrale	Woodall-Duckham (USA) Ltd.	(72)	-	(8)	Foreign	Commercial
Koppers-Totzek	Koppers Company, Inc.	-	-	(39)	Foreign	Commercial
Winkler	Davy Powergas	-	(23)	6(14)	Foreign	Commercial
Chapman (Wilputte)	Wilputte Corp.	2(12)	-	-	US	Commercial
Riley Morgan	Riley Stoker Corp.	1	-	-	US	Commercial
BCG/Lurgi Slagging	British Gas Corp. and Lurgi Mineralöltechnik GmbH	-	1	-	Foreign	Demonstration
Bi-Gas	Bituminous Coal Research, Inc.	-	1	-	US	Demonstration
Foster Wheeler/Stoic	Foster Wheeler/Stoic Corp.	1*(2)	-	-	US/Foreign	Demonstration/ Commercial
Pressurized Wellman-Galusha (MERC)	ERDA	1*	-	-	US	Demonstration
CFERC Slagging	ERDA	-	1*	-	US	Demonstration
Texaco	Texaco Development Corp.	-	-	1*	US	Demonstration
BCR Low-Btu	Bituminous Coal Research, Inc.	1*	-	-	US	Demonstration
Combustion Engineering	Combustion Engineering Corp.	1*	-	-	US	Demonstration
Bygas	Institute of Gas Technology	-	1	-	US	Demonstration (High-Btu)
Synthane	ERDA	-	1	-	US	Demonstration (High-Btu)
CO_2 Acceptor	ERDA	-	1	-	US	Demonstration (High-Btu)
Cogas	COGAS Development Co.	-	1	-	US	Demonstration (High-Btu)
Foster Wheeler	Foster Wheeler Energy Corp.	1	-	-	US	Pilot
Babcock & Wilcox	The Babcock & Wilcox Co.	1	-	-	US	Pilot
U-Gas	Institute of Gas Technology, Phillips Petroleum Corp. Sterns-Roger	1	-	-	US	Pilot
Westinghouse	Westinghouse Electric Corp.	1	-	-	US	Pilot
Coalex	Inex Resources, Inc.	1 (1*)	-	-	US	Pilot Commercial
Wellman Incandescent	Applied Technology Corp.	(2*)**	-	-	US/Foreign	Commercial/ Demonstration

*Under construction.
Demonstration scale indicates 2000 to 10,000 lb/hr coal feed.
Pilot scale indicates 400 to 1500 lb/hr coal feed.

**Undetermined number overseas

Source: Radian Corporation (1977)


Coal
Preparation
Coal Lock
Raw Gas
Purification
Gasifier
Steam
Oxygen
Ash Lock
Ash

Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC. Adapted from Bodle and Vyas (1973).

Figure 7. Lurgi low Btu coal gasification process

Table 4. Water and Material balance[a] for a 7.08×10^6 m^3/d Lurgi gasification plant

Input	Quantity	Output	Quantity
Coal[b]	10,770 tpd[c]	Intermediate Btu gas	250×10^9 Btu/day
Water	U	Solid waste	865 tpd
		Sulfur dioxide[d]	0.83 tpd

Water consumption by category	l/min	Percent
Discharge or evaporation	28,836	56.7
Reaction	14,920	31.5
Vent	606	1.3
Drift	1,968	4.2
With ammonia	757	1.6
Wet ash	1,136	2.4
Fuel and incineration	1,090	2.3
Total	47,313	100.0
Water supplies by category		
Water supply source	37,434	79.1
Coal	5,413	11.4
Products of methanation	4,466	9.5
Total	47,313	100.0

U = unknown.

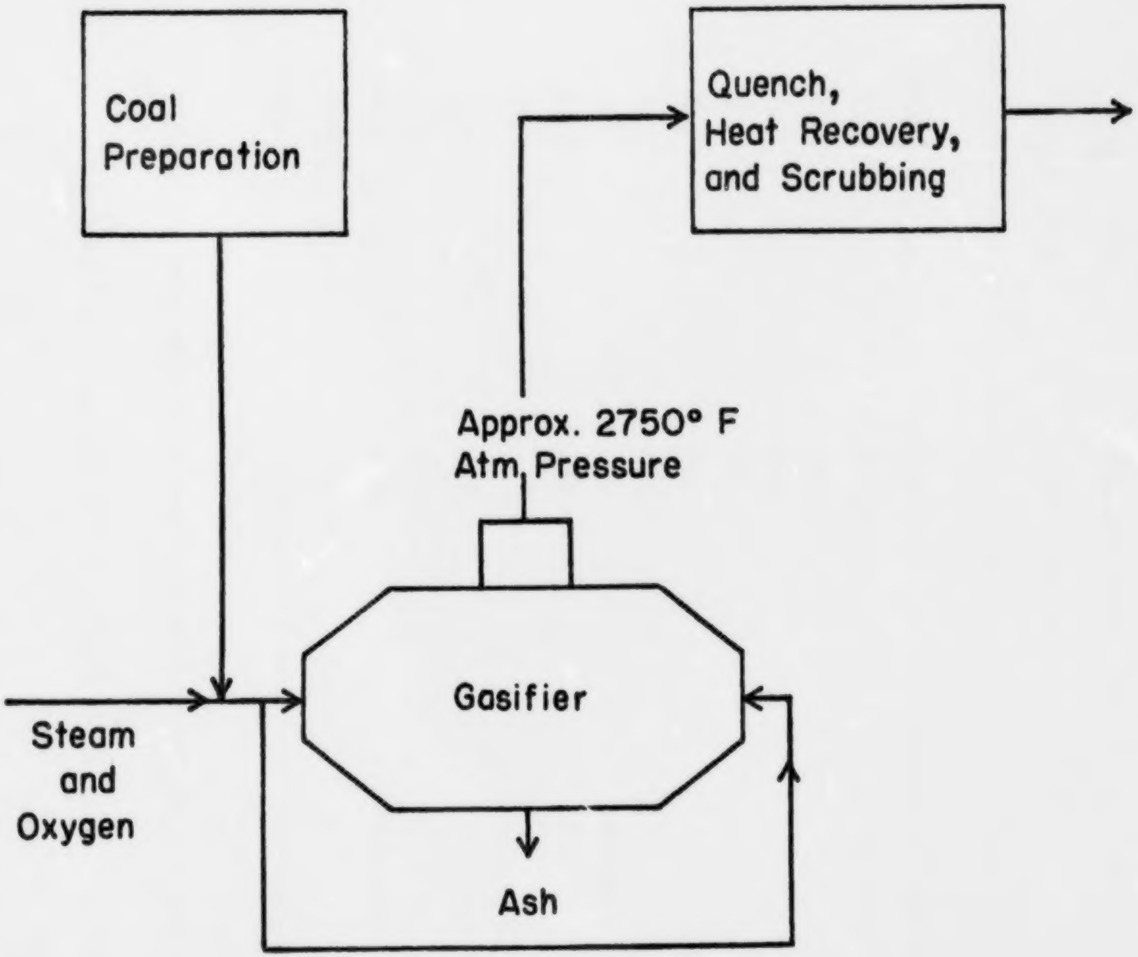
[a] Assumes the use of a methanation step following gasification and sulfur removal.

[b] Using Northwest coal of 8,780 Btu/lb, 6.77% ash, and 0.85% sulfur.

[c] Tons per day.

[d] Controlled emission.

Source: Hittman Associates, Inc. 1975[b]. Environmental impacts, efficiency, and cost of energy supply and end use. Final report, Vol. II. Columbia MD, p. III-29.


Coal Preparation
Quench, Heat Recovery, and Scrubbing
Approx. 2750° F Atm. Pressure
Gasifier
Steam and Oxygen
Ash

Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC. Adapted from Bodle and Vyas (1973).

Figure 8. Koppers-Totzek coal gasification process

The Koppers-Totzek process offers an advantage of not producing byproduct tars, oils, etc., owing to its higher operating temperature. The higher operating temperature, however, also is a disadvantage in SNG production. The SNG produced has a low methane content (1%) and the size of the methanation unit must almost be doubled. Other disadvantages are greater oxygen consumption and low operation pressure. The resultant SNG has to be compressed to a final pipeline pressure of about 74 kg/cm^2 (1050 psi).

I.B.3.c. Bureau of Mines Stirred Fixed Bed. In the BuMines process, pulverized coal is fed into the top of the reactor from a lock hopper and falls down onto a rotating grate similar to the one used in the Lurgi process (Figure 9). However, a stirrer is mounted in the center of the reactor and a variable speed drive both rotates the stirrer and moves it vertically. This prevents clogging and allows caking coals to be used. Steam and air are injected from below the grate.

The dimensions of a commercial-sized reactor have not been determined. The plant has been operated at pressures ranging from atmospheric to 21 kg/cm^2 (300 psi).

I.B.3.d. Westinghouse Fluidized-Bed Gasifier. Two pressurized, fluidized-bed vessels are used in the Westinghouse system, one as the gasifier and the other as a devolatilizer/desulfurizer. Air, steam, and char react in the gasifier to produce a hot gas which is then introduced into the devolatilizer/desulfurizer with crushed coal and dolomite (lime) (Figure 10). Hot gases from the gasifier supply the heat for devolatilization and the char produced by devolatilization is used as the feedstock for the gasifier. Sulfur is removed by the dolomite.

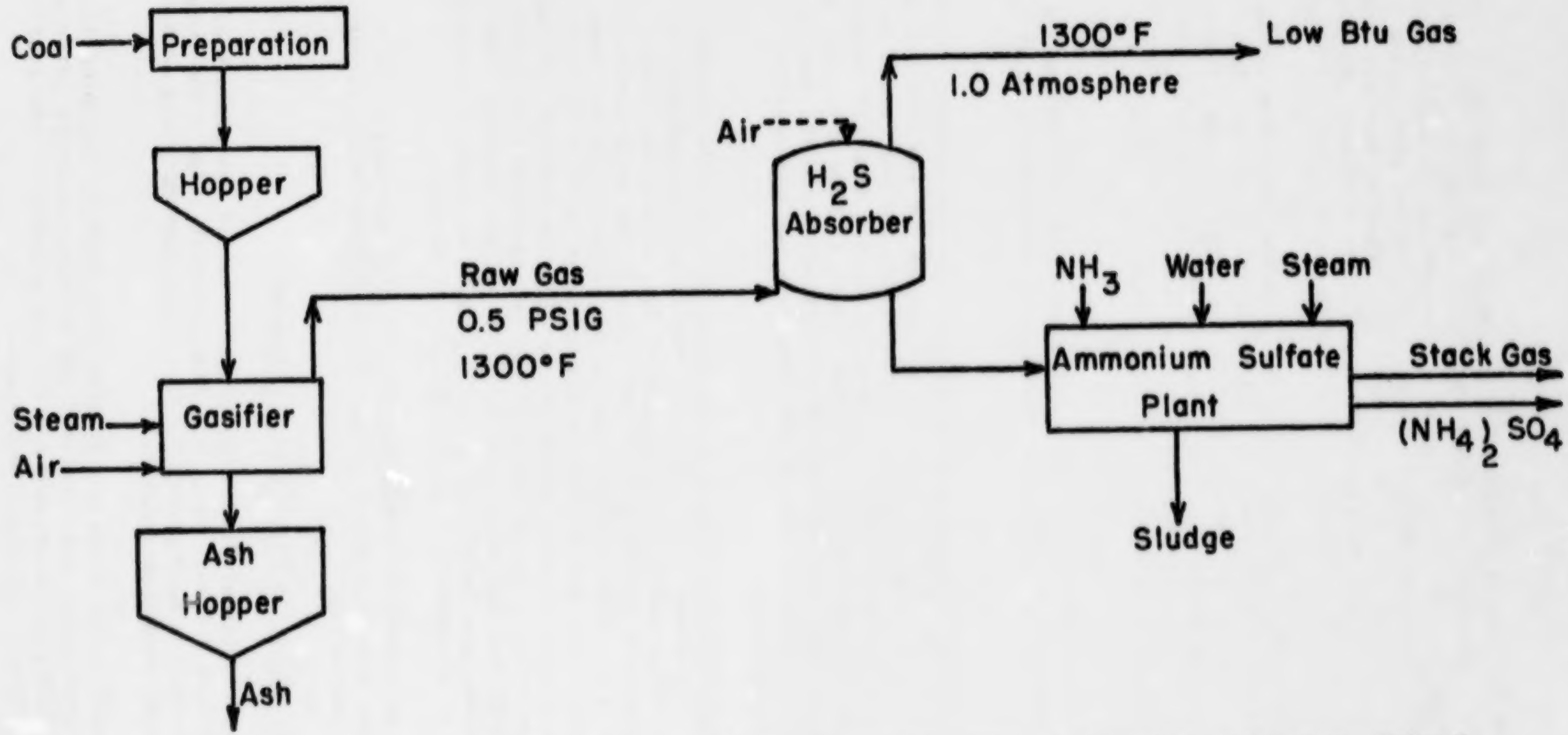
I.B.3.e. Ash Agglomerating Fluidized-Bed Gasifier. In this process, pulverized coal is introduced into a pressure vessel and is partially burned at high temperature while suspended by an upward flow of air and steam. The ash slowly agglomerates in the reactor and falls to the bottom where it is removed. (Figure 11). Fine particulates in the produced gas are removed by a cyclone scrubber. The gas is then cooled to about 1,032°K (1,400°F) and passed through a filter where dolomite reacts with any hydrogen sulfide to form a sulfurized solid. The dolomite filter is regenerated periodically by treating it with hot carbon dioxide to drive off the sulphur. The hot, cleaned, pressurized gas (which has a heating value of about 160 Btu's/ft^3 is then fed to a combined cycle electric power plant.

The system, now in prototype development, has a high throughput for a particular reactor vessel size and relies on the agglomerating characteristics of coal to remove ash.

I.B.4. Specific High Btu Gasification Processes

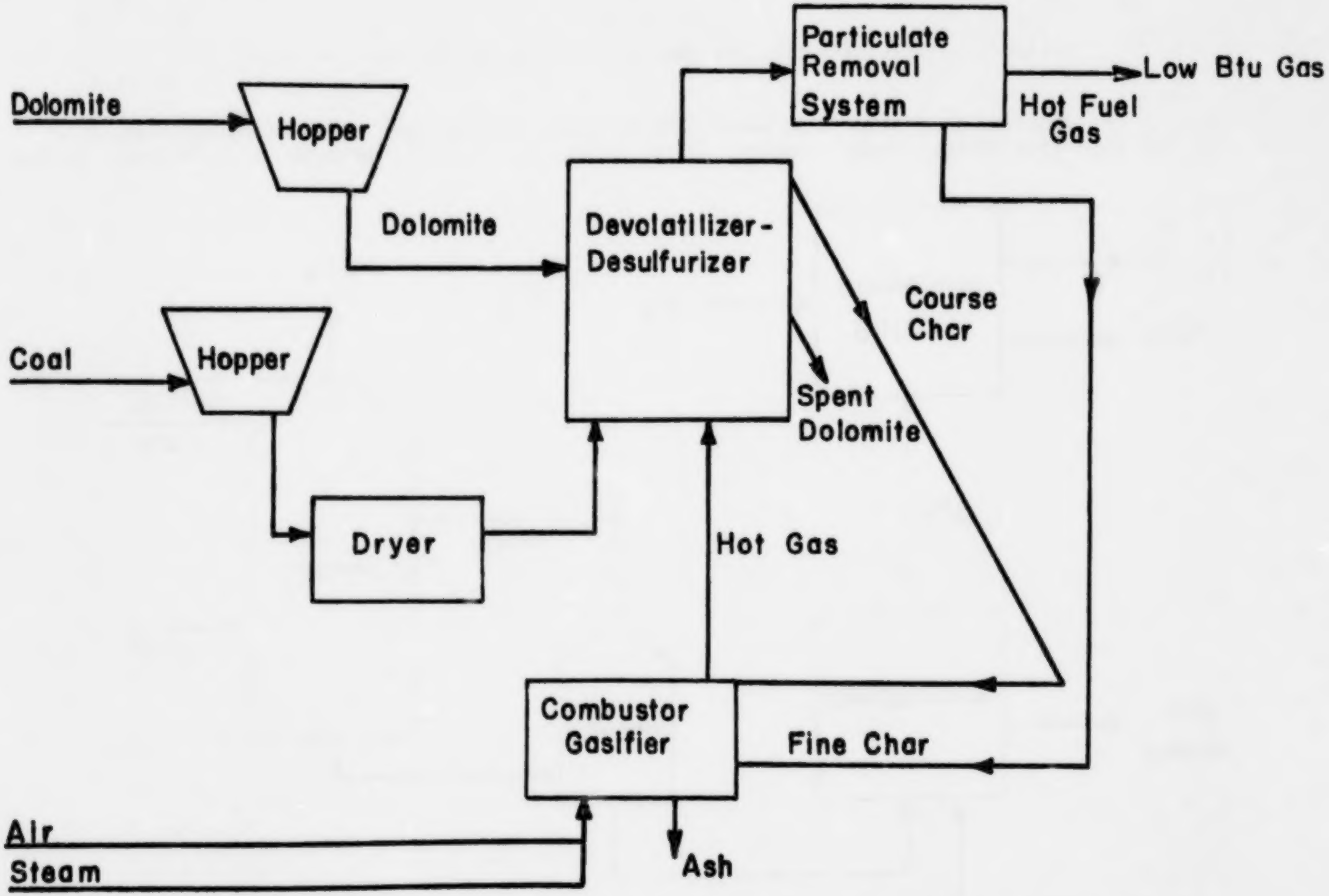
The major characteristics of five high Btu gasification systems are identified in Table 5. All five systems are in the developmental stage. The Lurgi gasification process has been proven but the final upgrading and methanation steps have not been used commercially.

Most high Btu gasification processes include pretreatment, gasification, clean up, shift conversion, purification, and methanation steps (discussed in Section I.B.1). Differences between systems are greatest in the gasification step. These differences are highlighted below.


Coal
Preparation
Hopper
Steam
Air
Gasifier
Ash Hopper
Ash
Raw Gas
0.5 PSIG
1300°F
Air
H_2S Absorber
1300°F
1.0 Atmosphere
Low Btu Gas
NH_3
Water
Steam
Ammonium Sulfate Plant
Stack Gas
$(NH_4)_2SO_4$
Sludge

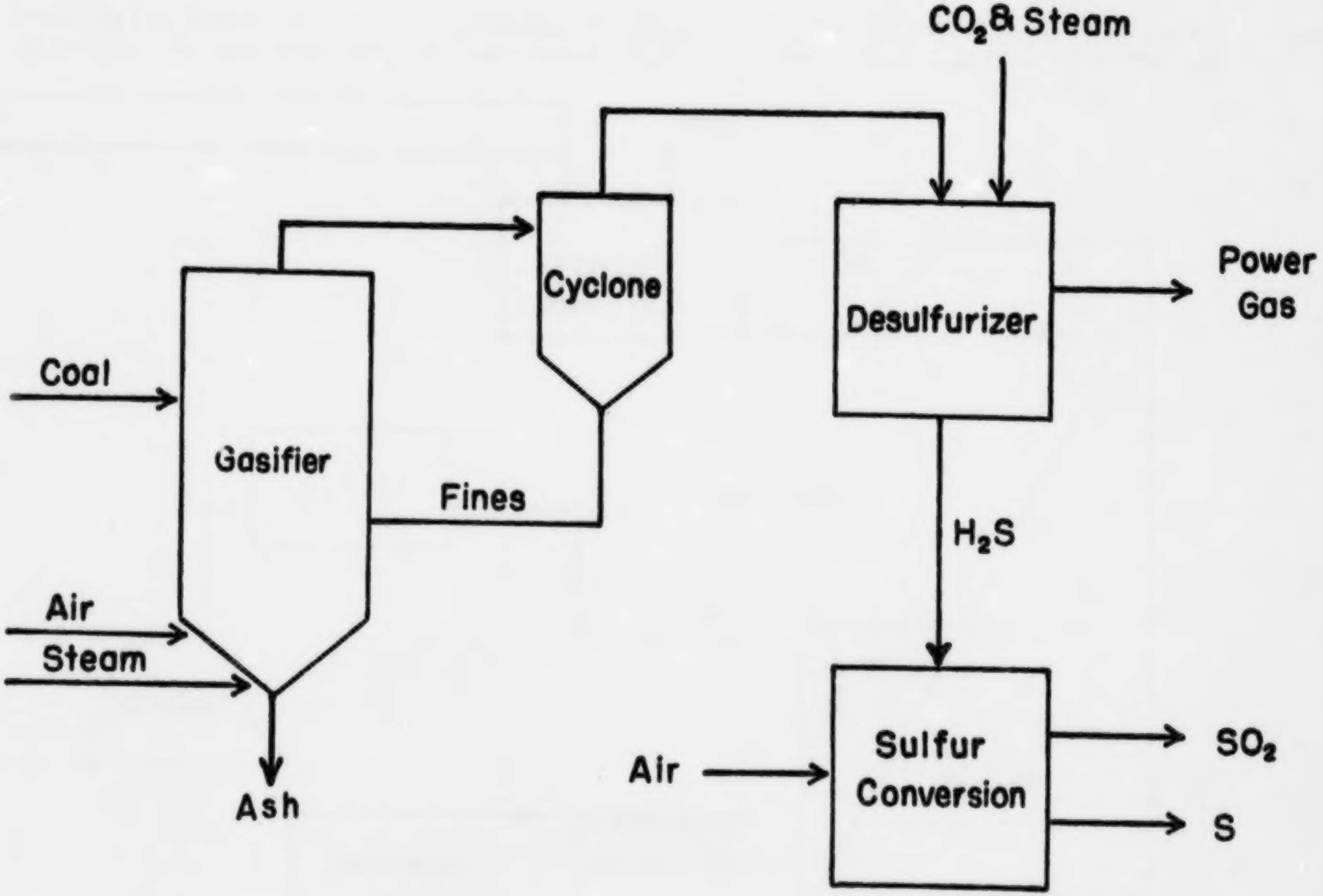
Source: Interagency Synthetic Fuels Task Force. 1974. Report to Project Independence blueprint, Federal Energy Agency. Supplement 1, prepared under direction of USDI, Washington DC. Cited in University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC.

Figure 9. Bureau of Mines stirred fixed bed coal gasification process


Dolomite
Hopper
Dolomite
Coal
Hopper
Dryer
Devolatilizer-Desulfurizer
Particulate Removal System
Low Btu Gas
Hot Fuel Gas
Course Char
Spent Dolomite
Hot Gas
Combustor Gasifier
Fine Char
Air
Steam
Ash

Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC. Adapted from Archer, et al. (1974).

Figure 10. Westinghouse fluidized bed coal gasification process


CO₂ & Steam
Coal
Gasifier
Cyclone
Desulfurizer
Power Gas
Fines
H₂S
Air
Steam
Ash
Air
Sulfur Conversion
SO₂
S

Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC. Adapted from Archer, et al. (1974).

Figure 11. Ash agglomerating fluidized bed coal gasification process

Table 5. Selected design features of five high Btu gasification processes

Name	Reactor type	Bed type	Pressure (lbs/in^2)	Hydrogen sources	Oxygen sources	Heat	Pretreatment	Coal input
Lurgi	Gasifier	Modified fixed	300-500	Steam	Oxygen plant	Direct	Sizing	Noncaking, 1/4x2", no fines
HYGAS	Hydrogasifier	Fluidized	1,000	Hydrogen[a]	Oxygen plant	Direct	Sizing, heating, and slurry	8 to 100 mesh fines all coals
BI-GAS	Gasifier and hydrogasifier	Entrained flow	1,000	Steam	Oxygen plant	Direct	None	Liquid to rank A bituminous pulverized
Synthane	Gasifier devolatilizer	Fluidized	1,000	Steam	Oxygen plant	Direct	Sizing and heat and volatilize	All coals fines of 200 mesh
CO_2 acceptor	Gasifier devolatilizer	Fluidized	150	Steam	Air	Direct and indirect	Sizing	Lignite or subbituminous, 1/8"

[a] Hydrogen introduced into the gasifier is produced by reaction of steam, char, and oxygen.

Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC.

I.B.4.a. Lurgi High Btu Gasification. The initial gasification step used in Lurgi is essentially the same for low and high Btu gasification. Synthesis gas from the gasifier shown in Figure 12 has a Btu value of approximately 285 Btu/ft^3. The upgrading process is the same as the general process described earlier including cooling shift conversion, purification, and methanation (Corey 1974). Pilot plant configurations of these steps have been tested in Scotland and South Africa but data concerning both plants are proprietary.

Each gasifier reactor is capable of producing about 10 million cubic feet (mmcf) of synthetic natural gas per day. The inputs and outputs of a 250-mmcf-per-day Lurgi gasification plant are summarized in Table 6.

I.B.4.b. HYGAS. In the HYGAS process, pulverized coal of a nominal -8/+100 mesh size is slurried with hot aromatic by-product oil and pumped into the gasification reactor. This reactor, which operates at 1,000 psi, has been heated and supplied with a hydrogen-rich gas from a separate char-gasifier vessel (Figure 13). As the coal slurry enters the reactor, light oils and gases vaporize upward and the coal falls down into a fluidized bed. Total coal residence time in the gasification reactor is about 30 minutes. The devolatilized coal goes from the gasification reactor into the char gasifier where hydrogen-rich gases are produced from the reaction of char, steam, and oxygen (Hittman, 1975. Volume II). The HYGAS process differs from other processes primarily in its use of slurry feed and a hydrogen-rich gasifier atmosphere.

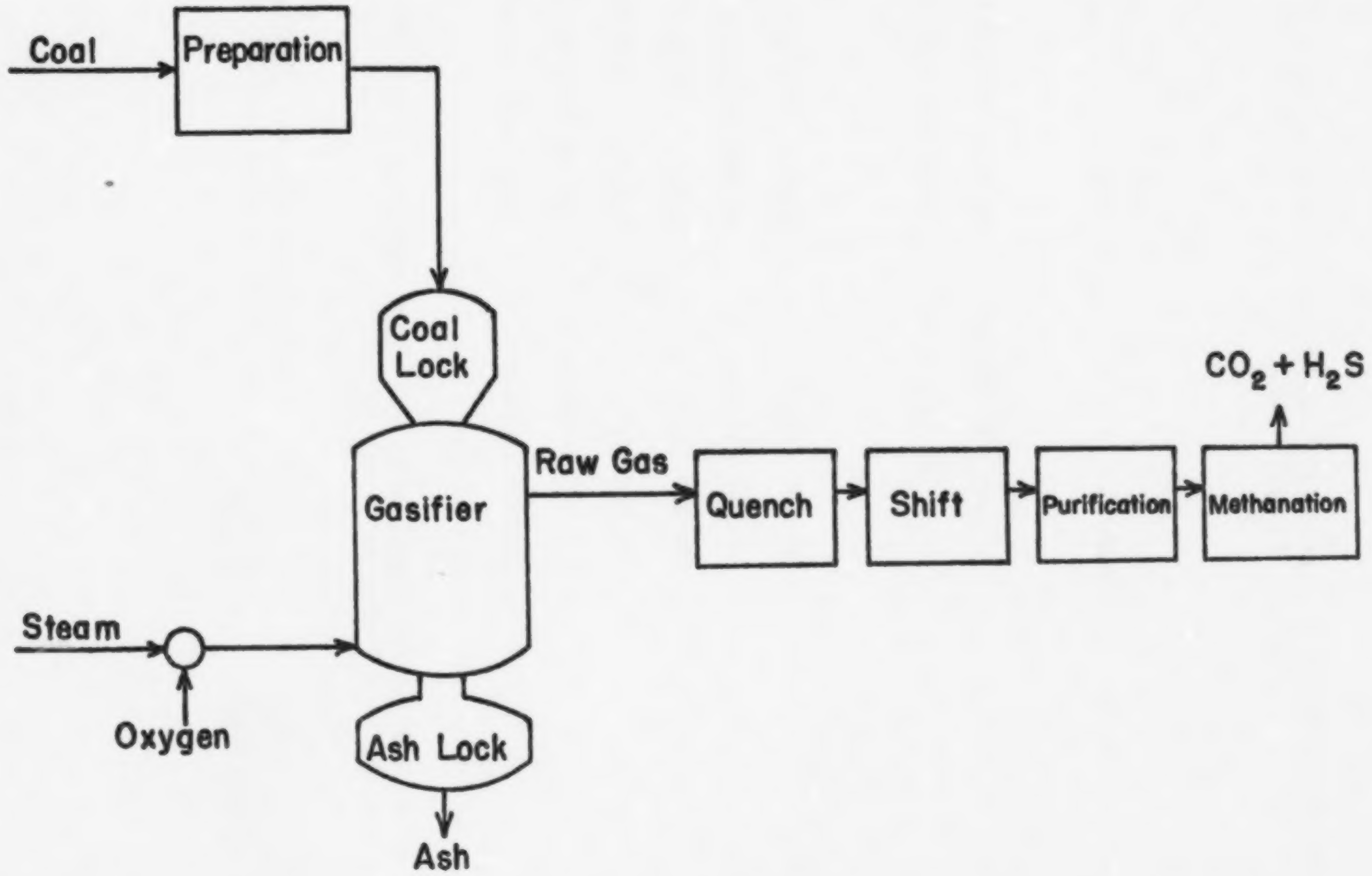
After leaving the gasification reactor, the raw gas is cooled, the aromatic oil is recycled, and other tars and oils are removed as byproducts. The gas is then processed by water-gas shift conversion, purification, and methanation.

The HYGAS process is one of the most complex gasification systems being developed and has separate circulation systems for coal, char, and byproduct oil. Its advantages include the use of pumped slurries instead of lock hoppers and the efficiency gained by using a hydrogen-rich gas for the hydrogasification reactions. Although commercial plant size information is not available, about 10 gasifiers would be needed for a commercial plant.

I.B.4.c. BI-GAS. In the BI-GAS process, pulverized coal is piston-fed into the middle of a 1,000 psi gasifier reactor where it is mixed with steam. The coal is devolatilized by a rising flow of hot gases which are produced from char (Figure 14) (Hittman, 1975. Volume II). The gases and char are then separated and the char is piped to the bottom of the gasifier where it is mixed with steam and oxygen. An ash slag is removed from the bottom of the vessel. The process gas stream undergoes cleaning, shift conversion, purification, and methanation.

I.B.4.d. Synthane. In the Synthane process, coal sized to pass through a 200-mesh screen is mixed with steam and oxygen in a pretreatment pressure vessel at 1,000 psi and 427°C (800°F) (Figure 15). In this pretreatment stage, the coal is partially oxidized and volatile matter is driven off.

The coal and gases from the pretreater are introduced at the top of the gasifier and additional steam and oxygen are introduced at the bottom. Partial combustion of the coal increases the temperature of this process to


Coal
Preparation
Coal Lock
Gasifier
Raw Gas
Quench
Shift
Purification
Methanation
$CO_2 + H_2S$
Steam
Oxygen
Ash Lock
Ash

Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC. Adapted from Bodle and Vyas (1973).

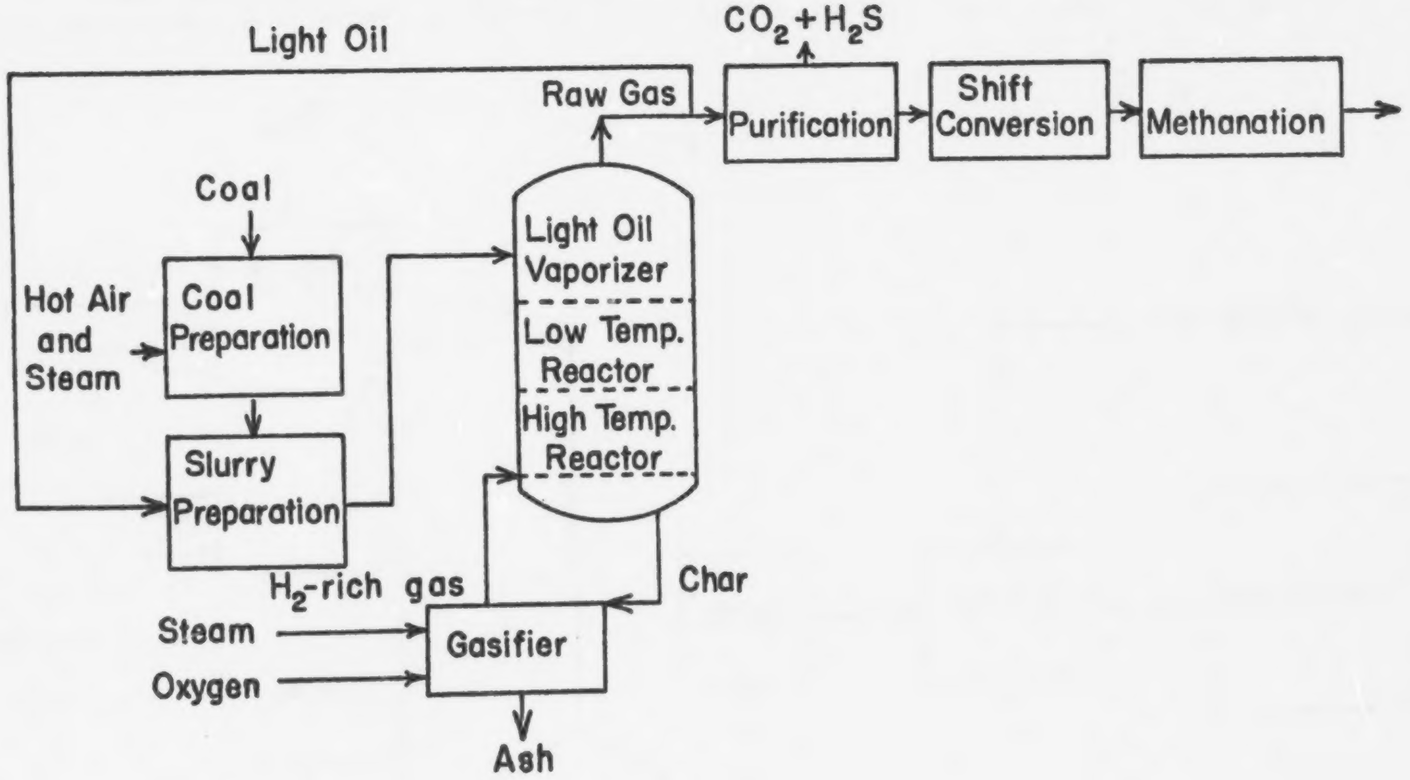
Figure 12. Lurgi high Btu coal gasification process

Table 6. Gasification material balance: Inputs and by-products for a Lurgi gasification plant[a]

Item	Quantity	Unit
Input:		
Coal	21,450,000 (23,600)	kg/day (ton/day)
Water	3.5×10^7 (9.3×10^6)	liter/day (gal/day)
Output:		
Solid waste	1,407,000 (1548)	kg/day (ton/day)
Air emission	34,000 (37.3)	kg/day (ton/day
Ammonia	102,000 (112)	kg/day (ton/day)
Sulfur	105,000 (116)	kg/day (ton/day)
Tar	4.3×10^6 (4.09×10)^3	J/day (Btu/day)
Naphtha	123,600 (32665)	liter/day (gal/day)

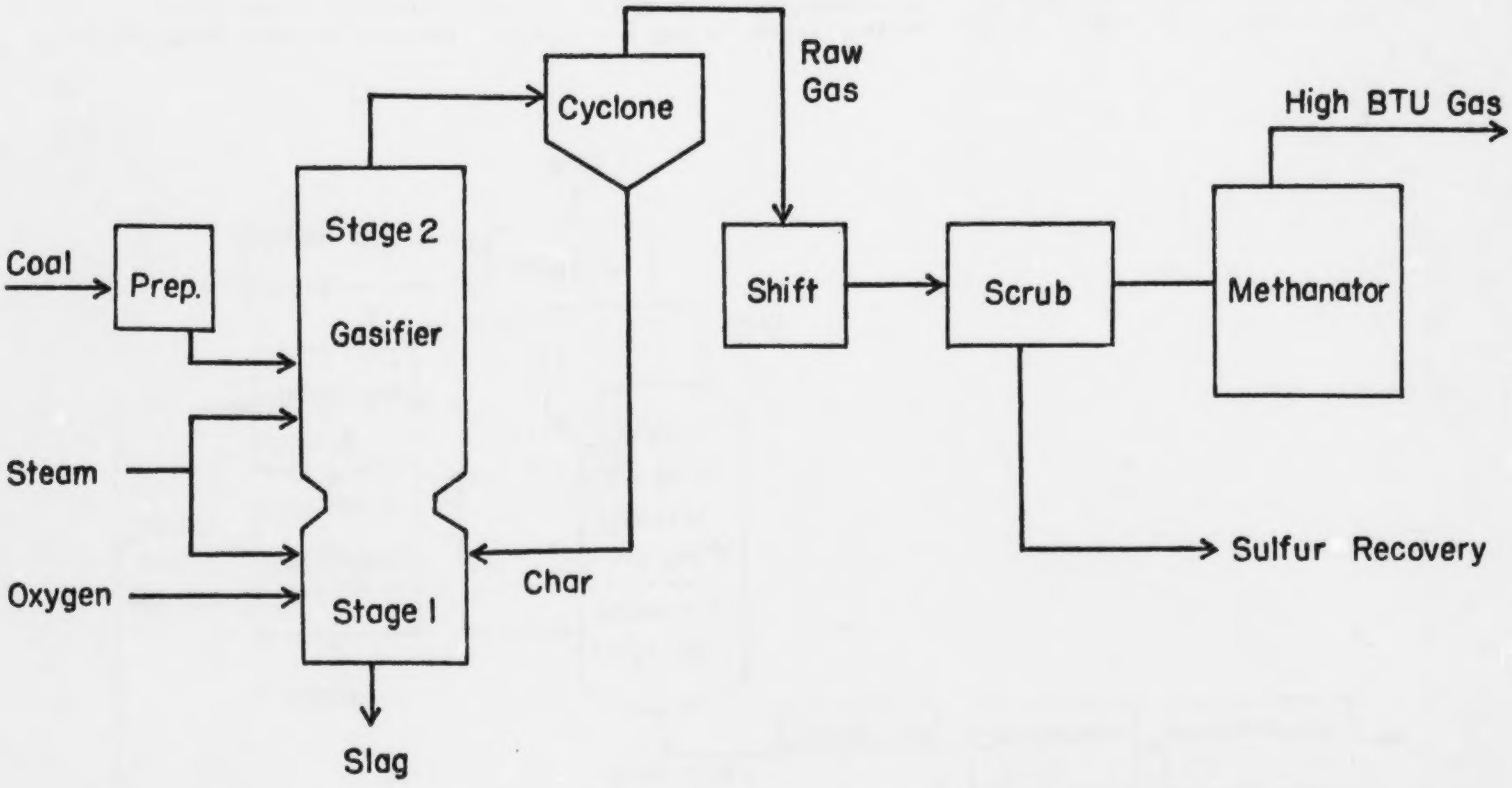
[a] 7.08×10^6 m^3/d (250 mmcf/d) plant, using Northwest coal at 2.0401×10^7 J/kg (8,780 Btu/lb), 6.77% ash, and 0.85% sulfur.

Source: Hittman Associates, Inc. 1975[a]. Environmental effects, impacts, and issues related to large-scale coal refining complexes. NTIS FE-1508-T2. Columbia MD.


$CO_2 + H_2S$
Light Oil
Raw Gas
Purification
Shift Conversion
Methanation
Coal
Coal Preparation
Hot Air and Steam
Slurry Preparation
Light Oil Vaporizer
Low Temp. Reactor
High Temp. Reactor
H_2-rich gas
Char
Steam
Oxygen
Gasifier
Ash

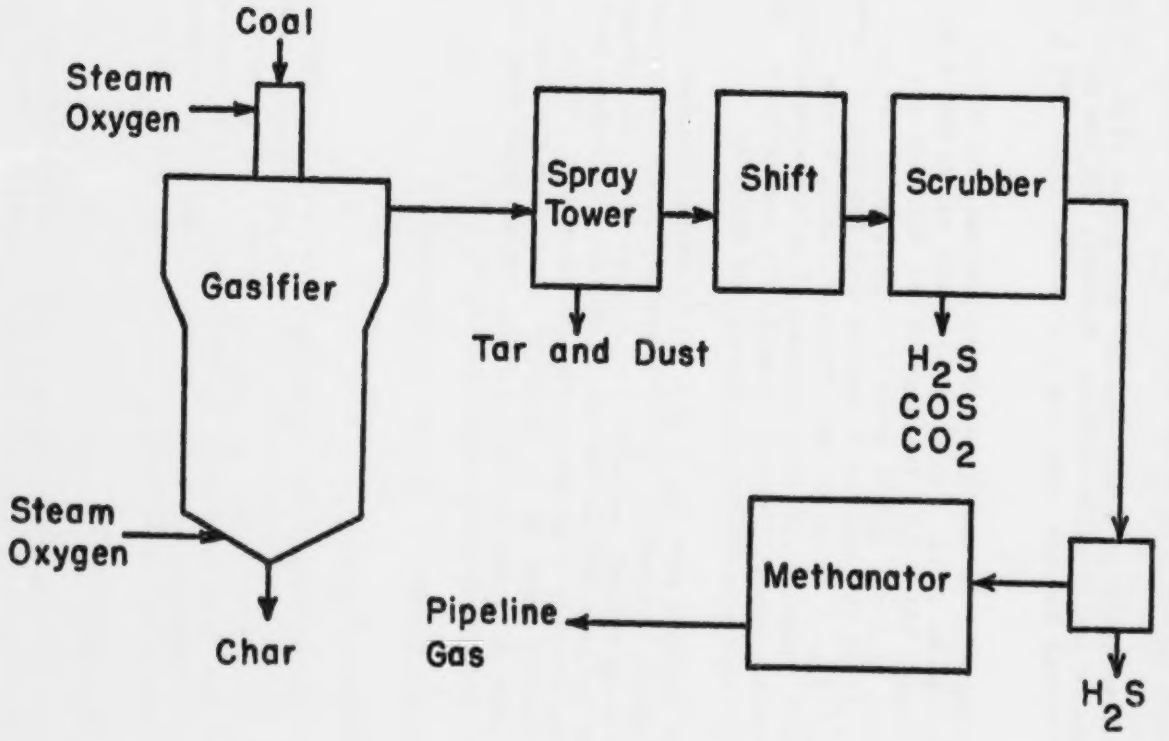
Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC. Adapted from Bodle and Vyas (1973).

Figure 13. HYGAS coal gasification process


Coal
Prep.
Steam
Oxygen
Stage 2
Gasifier
Stage I
Slag
Cyclone
Char
Raw Gas
Shift
Scrub
Methanator
High BTU Gas
Sulfur Recovery

Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC. Adapted from Goodridge (1973).

Figure 14. BI-GAS coal gasification process


Coal
Steam
Oxygen
Gasifier
Steam
Oxygen
Char
Spray Tower
Tar and Dust
Shift
Scrubber
H_2S
COS
CO_2
Methanator
Pipeline Gas
H_2S

Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC. Adapted from Bureau of Mines (1974).

Figure 15. Synthane coal gasification process

980°C (1,800°F). After the coal passes through the fluidized-bed portion of the gasification vessel, it exits as char at the bottom. The char is burned to produce steam for the pretreater and gasifier (Hittman, 1975. Volume II).

The raw gas is cleaned of tars, char, and water and then undergoes a shift conversion. Following those operations, the gas is bubbled through hot carbonate to remove carbon dioxide and sulfur and is then methanated.

The Synthane process achieves a high Btu raw gas output with a relatively simple high-pressure gasification system. However, all the coal entering the gasifier is not burned and the remaining high sulfur char must be burned for process heat.

I.B.4.e. CO_2 Acceptor. In the CO_2 Acceptor process, pulverized coal and hot dolomite are introduced at the top of the reactor and steam is introduced at the bottom (Figure 16). Both the heat of the dolomite and its energy-producing reaction with the carbon dioxide (a product of the coal-steam reaction) devolatilize the coal as it passes down the reactor vessel. The partially combusted coal exits as char (Hittman, 1975. Volume II). Both the char and spent dolomite are then introduced as separate streams into a dolomite regenerator vessel. In this vessel, the combustion of char with air heats the dolomite and drives off the carbon dioxide.

The CO_2 Acceptor process produces a gas low in carbon dioxide, carbon monoxide, and sulfur. A shift in reaction is not necessary since the carbon monoxide-to-hydrogen ratio is already suitable for methanation. The advantages of the CO_2 Acceptor process are in the use of dolomite to remove some of the sulfur and carbon dioxide from the synthesis gas stream. Because dolomite is used as the oxidizing agent in the gasifier vessel, oxygen does not have to be supplied. These advantages, however, must be balanced with the complexity of plant design for the dolomite regeneration system.

I.C. PROJECTED TRENDS IN INDUSTRY DEVELOPMENT

I.C.1. Locational Changes

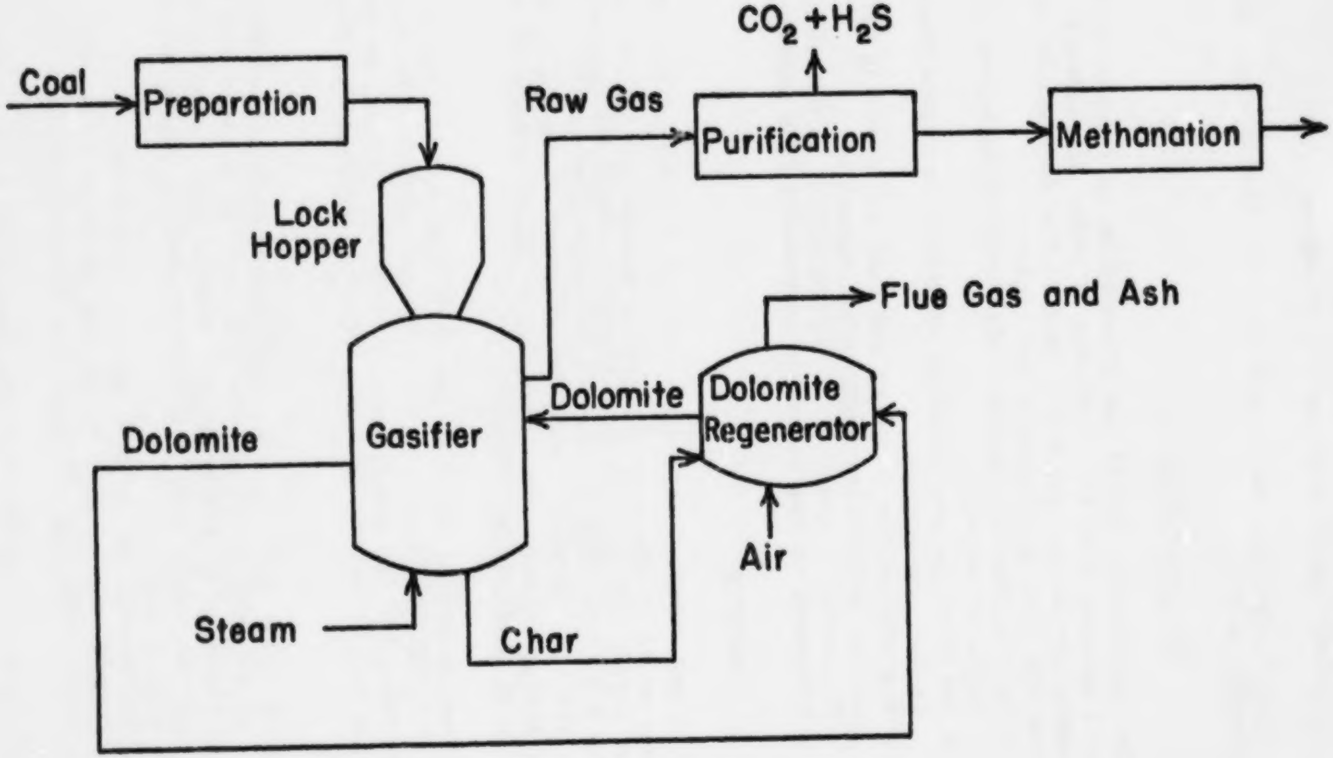
Currently there are no full scale commercial coal gasification facilities in the U.S. but a number of proposals for both demonstration and commercial gas production are in various stages of implementation. It is generally anticipated that most new facilities will be established in coal mining regions in order to reduce transportation costs for the raw materials. These plants may be mine mouth facilities or located on separate but nearby sites.

I.C.2. Raw Materials

Coal gasification processes will operate with a variety of coal types. The Lurgi process has been unable to use caking and unsized coals but, as mentioned earlier, this restriction may soon disappear. However, the development of new processing techniques will largely confine the Lurgi process to surface mined coals which have a low production cost to balance the processing costs.

I.C.3. Processes

As has been mentioned on several occasions in this document, a variety of processes are under study and/or development. The focus has been on processes


Coal
Preparation
Lock
Hopper
Raw Gas
Purification
$CO_2 + H_2S$
Methanation
Gasifier
Dolomite
Dolomite
Regenerator
Flue Gas and Ash
Air
Dolomite
Steam
Char

Source: University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis. GPO 041-011-00025-4, Washington DC. Adapted from Bodle and Vyas (1973).

Figure 16. CO_2 acceptor coal gasification process which result in

- Maximum cost effectiveness
- Low environmental impacts
- Production of high quality products

The actual processes which will dominate the industry cannot be predicted at this point in time.

I.C.4. Pollution Control

Radian Corporation (1977) has prepared an up to date review of pollution control systems that are available or under development. In general the following approaches are being used in the development of pollution control systems for coal gasification facilities:

- Utilization of processes with reduced emissions and more controllable fugitive emissions
- Improved gas purification processes to reduce impurities in the product gas stream
- Upgraded sulfur recovery and tail gas cleaning processes to reduce sulfur and complex hydrocarbon emissions
- Processes to treat cyclic hydrocarbons in wastewaters
- Processes to remove acidic components from wastewaters

I.D. MARKETS

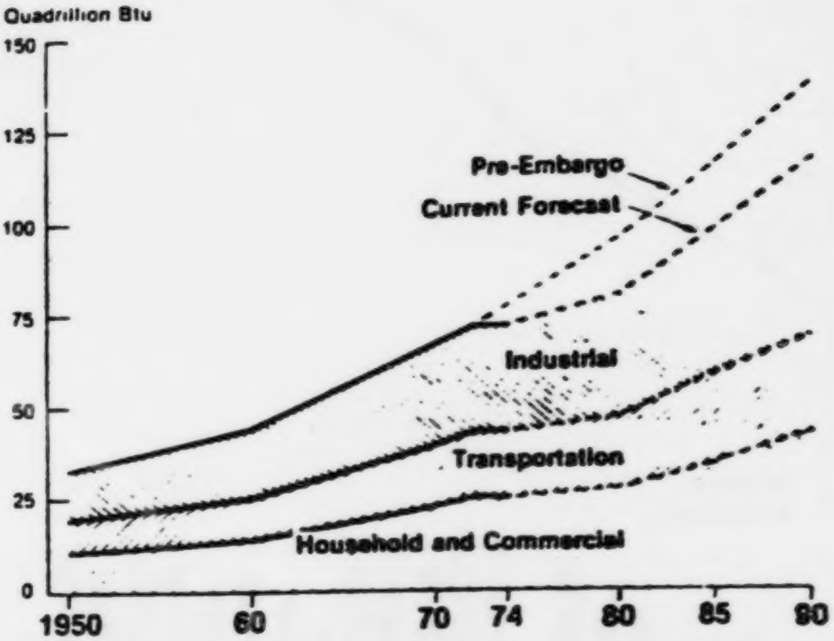
Natural gas, electricity, fuel oil, and low sulfur coal are in short supply in many areas of the U.S. Projected demands for natural gas exceed the future supply (US-DOI, 1978). Figure 17 shows the consumption of energy in the U.S. from 1950 to 1974 and a projection to 1990. Beginning about 1950, the U.S. changed from a net exporter of energy to a net importer. Since 1958, energy imports have increased at rates between 7% and 10% (National Academy of Engineering, 1974).

Total energy use in the U.S. has more than doubled since 1950, increasing at a rate of 4.25% per year. During the same period, domestic energy production has increased at an annual rate of only 3%. During recent years, production increase has slowed to less than 1% (Ford Foundation, Energy Policy Project, 1974).

Figure 18 shows domestic gas reserves and annual consumption from 1947 to 1974. It is evident that there will soon be a large unsatisfied demand for natural gas even if all available sources are developed to the maximum. Moreover, the gas supply will continue to decline unless one or more of the following events take place:

- New sources of natural gas are discovered
- Significant volumes of SNG are produced from coal
- Other technological means are found to produce natural gas.

Several factors contribute to the demand for natural gas. Pipelines were built after World War II forming a transport network which made gas available throughout much of the country. A large number of homes and industries became dependent on natural gas because of its low price, clean burning characteristics, and availability. Industries on interruptible gas contracts could enjoy a relatively continuous supply of energy at a very low price. Since 1967, however, industrial interruptions have become common and in some areas new industrial customers are being rejected.

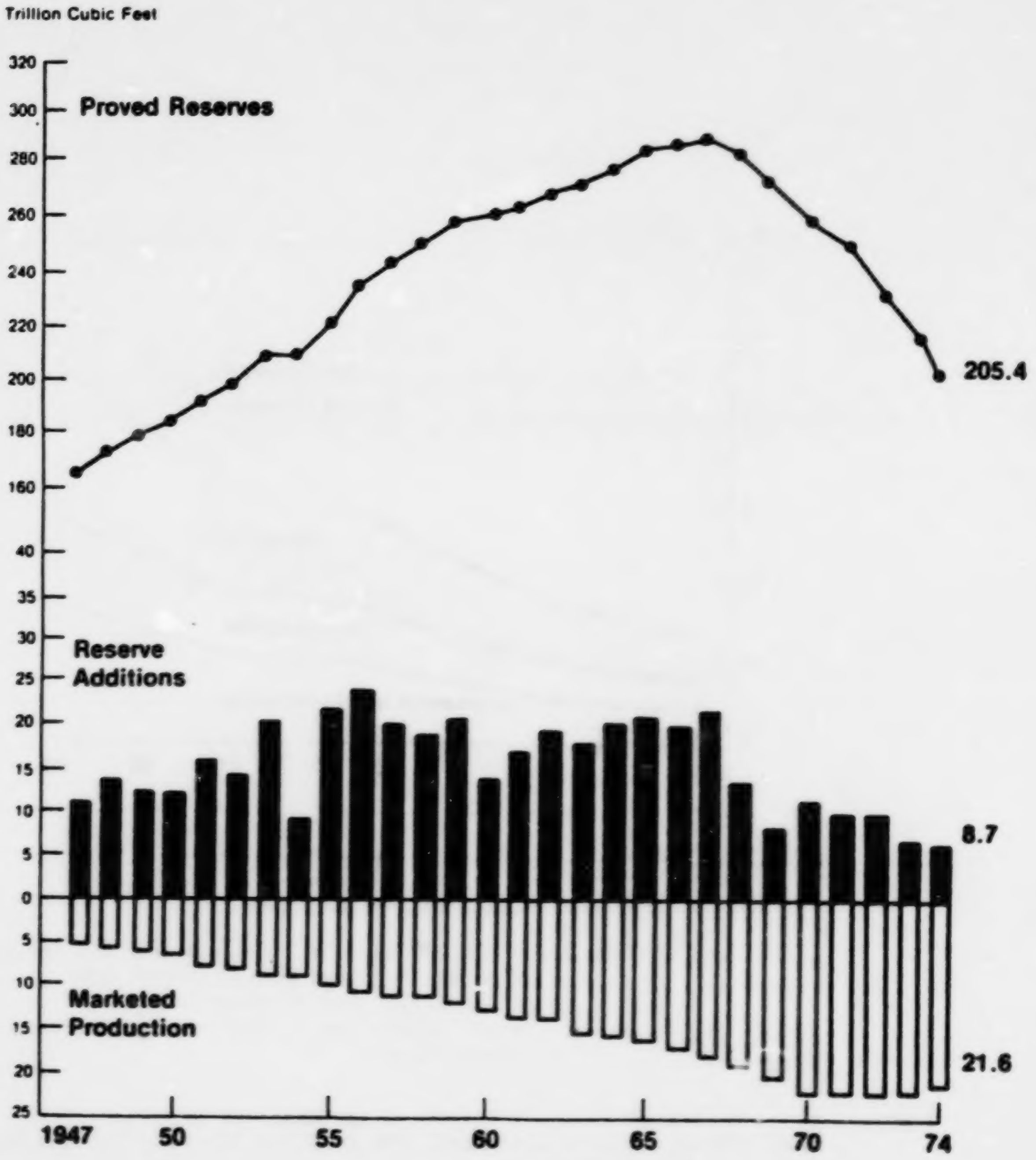


Rough Equivalences for U.S. Energy Data:

1 quadrillion Btu = 500,000 barrels petroleum per day for a year
= 40 million tons of bituminous coal
= 1 trillion ft^3 of natural gas
= 100 billion kwh (based on a 10,000 Btu/kwh heat rate

Source: U.S. Department of the Interior, Upper Missouri Region. 1978. Final environmental impact statement, ANG Coal Gasification Company North Dakota Project. FES78-1.

Figure 17. National energy consumption by sector from 1950 to 1974, and a projection from 1974 to 1990.



Source: American Gas Association, et al. 1975. Reserves of crude oil, natural gas liquids, and natural gas in the United States and Canada, and United States productive capacity, as of December 31, 1974.

Figure 18. U.S. natural gas reserves (excluding Alaska) and annual consumption from 1947 to 1974.

Total proven reserves of natural gas in the U.S. reached a peak of 293 trillion cubic feet (Tcf) in 1967 (Figure 18). Until that time, natural gas reserve additions exceeded production each year. Since 1968, production has exceeded reserve additions except for 1970 when Alaska's Prudhoe Bay reserves were added to the proved reserves (American Gas Association, 1975). During the past eight years, reserve additions in the lower 48 States have averaged 9.3 Tcf annually compared to an average production of 21.4 Tcf. In 1975 proven reserves with and without Alaska were 237 and 205 Tcf, respectively (US-DOI, 1978).

In July 1976, the Federal Power Commission in Opinion Number 770 authorized an increase in the price of natural gas sold in interstate commerce. This rate increase is expected to increase natural gas supplies for the short term; however, recoverable reserves are limited and for the long term the U.S. will need to find alternative means of producing energy. Based on these circumstances, it is reasonable to assume that more emphasis will be given to coal gasification technology with a likely increase in its marketability.

In the past, the extraction of methane from coal has been demonstrated in several pilot plants, both in the U.S. and abroad. This technology gives the U.S. a mid-term capability for expansion of coal reserves as supplement to domestic natural gas supplies.

However, to date, the commercial viability of a high Btu synthetic gas venture has not been demonstrated in the U.S. Estimates in 1976 indicate an investment of about $1 billion would be required to construct a high Btu gas plant capable of producing 0.08 Tcf/yr (assuming an investment debt/equity ratio of 75:25). About $525 million would be required to finance construction of a low Btu gas plant producing the equivalent of 0.05 Tcf/yr (assuming a debt/equity ratio of 50:50). The full costs, i.e., without incentives of both high and low Btu synthetic gas processes, expressed in 1975 dollars on a free on board (FOB) gasification plant basis, may be expected to range as shown in Table 7. Transmitting the high Btu gas output to consuming areas adds costs which vary depending on the proximity of the synthetic plants to natural gas transmission networks and consuming markets.

The technology involved in the production of low Btu gas is well developed and currently is applied in many commercial plants outside the U.S. A limiting factor in the use of low/medium Btu gas is that it may not be economically feasible to transport it more than 50 miles. This may be an inhibiting developmental factor if a plant is intended to generate electricity to residential, commercial, and industrial users in urban areas.

Although industry is considering a number of synthetic fuels projects, none has actually proceeded to the construction stage. Six major projects involving high Btu gas from coal are being planned. Several low Btu gas projects, for utility and industrial fuels, have been suggested but have not reached the level of planning associated with high Btu gas projects. None of the projects has acquired the financing and approvals needed to proceed. Only a few projects have reached the detailed design stage.

Coal gasification projects have not proceeded expeditiously because the risks associated with initiating synthetic fuels projects are large, in comparison with other investments which provide an equal or higher rate of return. One major risk is the uncertainty of future world oil prices. Other important

Table 7. Estimated costs by category for high and low Btu gasification facilities. Costs derived from draft report on synthetic fuels commercialization for President's Energy Resources Council, 1975.

Cost category ($/Mcf)	High Btu gas plant		Low Btu gas plant	
	Low estimates	High estimates	Low estimates	High estimates
Fixed costs	1.02	1.38	1.77	2.40
Operating and maintenance	.82	1.01	.61	.76
Feedstock of $11* to $17/ton	1.19	1.84	.72	1.11
Total at plant	3.03	4.23	3.10	4.27

*Feedstock cost of coal could be estimated at $5 to $9/ton, recognizing East and West regional experiences in coal production costs; with lower feedstock cost, high Btu gas would range between $2.38 and $2.34/Mcf.

Source: Federal Energy Administration. 1976. National energy outlook. FEA-N-75/713. GPO 041-018-00976. Washington DC.

risks include:

- Uncertainty about air and water quality standards
- Resource (coal, shale, biomass) availability as constrained by leasing rates and environmental concerns
- Availability of water
- Federal regulation of fuel prices
- Availability of labor, materials, and equipment
- Need for environmental control technology
- Extent of socioeconomic impact
- Unforeseen project delays.

However, in recognition of the diminishing natural gas supplies, the development of high and low Btu gasification plants may accelerate rapidly (with proper financial incentives) after 1980 and could reach about 1,060 billion cubic feet (Bcf) by 1985, 1,440 Bcf by 1990 (Federal Energy Administration, 1976).

Ultimately, the demand for gas products from coal will be established by regional needs for energy and for certain petroleum based chemicals such as ammonia. Table 8 illustrates the potential markets by Petroleum Allocation Districts (PAD) (Figure 19) for coal gasification facilities.

The determination of need for a specific gasification plant is complicated by the relationships between various sources of energy, both nationally and regionally. A systematic and complete analysis of project alternatives is essential to ensure investigation of all options. A methodology for the evaluation of alternatives is discussed in Section V.

I.E. SIGNIFICANT ENVIRONMENTAL PROBLEMS

I.E.1. Location

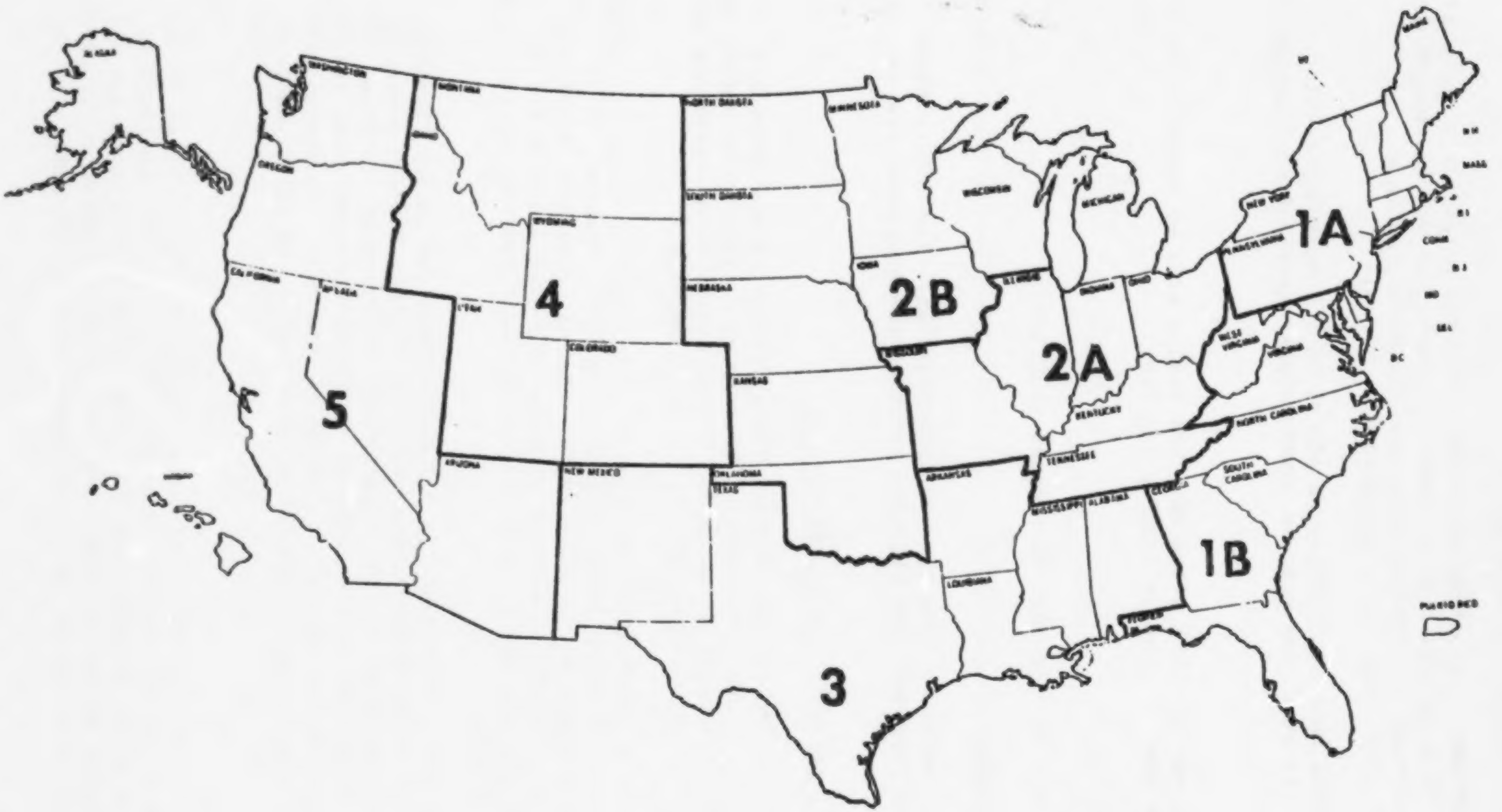
Coal gasification facilities generally are large installations which can occupy from 200 to 1,000 acres. Much of this acreage is necessary for containing a 90-day coal supply which safeguards the plant against a work stoppage in the coal mines or a breakdown in the transportation system for raw materials. The nature of these facilities locates them either in rural areas or on the periphery of an urban area in the coal mining regions. Because the siting of new source gasification plants can involve a significant change in land use, particularly in rural areas, direct and indirect social and ecological impacts occur. Direct impacts are primarily a result of the type of facility proposed and site specific conditions. The magnitude and significance of secondary or indirect impacts such as induced growth, infrastructure changes, and demographic changes depends largely on the local economy, existing infrastructure, numbers and characteristics of construction workers (e.g., local or nonlocal, size of worker's family), and other related factors. Long term secondary impacts are seldom significant unless the plant, because of its size, processing methods, and location, employs a large number of workers and thereby leads to the creation of spin-off developments (commercial, industrial, and residential). At the time of publication of these guidelines, the EPA's Office of Environmental Review was developing a method to assess the induced growth impacts of new source industries. The method will be available in early 1981.

Table 8. Markets for coal gasification plants

Coal conversion region	Crude deficiency (joules)	
	1980	1985
Markets for high joule gas:		
PAD Region I	$1.855 \times 10^6 - 2.37 \times 10^6$	$2.932 \times 10^6 - 4.206 \times 10^6$
PAD Region II	$3.71 \times 10^6 - 4.421 \times 10^6$	$4.516 \times 10^6 - 6.756 \times 10^6$
PAD Region III	$2.019 \times 10^6 - 3.113 \times 10^6$	$3.584 \times 10^6 - 6.483 \times 10^6$
PAD Region IV	$1.676 \times 10^5 - 2.94 \times 10^6$	$2.287 \times 10^5 - 4.82 \times 10^5$
PAD Region V	$2.098 \times 10^6 - 2.524 \times 10^6$	$1.217 \times 10^6 - 1.832 \times 10^6$
Markets for low joule gas:		
Northwestern Great Plains	$4.072 \times 10^{17} - 1.629 \times 10^{18}$	$8.854 \times 10^{17} - 8.540 \times 10^{18}$
Four Corners	$4.426 \times 10^{18} - 7.986 \times 10^{18}$	$6.402 \times 10^{17} - 2.90 \times 10^{19}$
Central	$2.2134 \times 10^{17} - 1.9478 \times 10^{19}$	$4.427 \times 10^{17} - 7.00 \times 10^{19}$
Appalachian	$6.644 \times 10^{17} - 1.062 \times 10^{19}$	$2.2134 \times 10^{17} - 6.467 \times 10^{19}$

PAD = Petroleum Allocation District.

Source: U.S. Department of the Interior, Office of Coal Research. 1974. Prospective regional markets for coal conversion plant products projected to 1980 and 1985. Washington DC.



Source: Federal Energy Administration. 1976. National energy outlook. FEA-N-75/713. GPO 041-018-00097-6, Washington DC.

Figure 19. Geographic location of Petroleum Allocation Districts (PAD)

I.E.2. Raw Materials Transportation

The major environmental problems associated with raw materials occur during coal's mining and transport. Guidelines for the assessment of coal mining's impacts are contained in separate guideline documents, so this discussion will cover only the transportation of coal.

After mining, coal must be transported either to a processing facility or to the site of its use. Raw coal is almost always transported from the mine by:

- Rail
- Barge (a system which often involves moving coal by truck or train from the mine to a barge loading facility)
- Truck
- Pipeline

The impact of each is discussed in Section II.C.3.

I.E.3. Processes

The primary environmental contaminants associated with low/intermediate Btu gasification processes and high Btu gasification processes are described below.

I.E.3.a. Low/Intermediate Btu Gasification

Residuals from four low to intermediate Btu gasification processes are summarized in Table 9 and are discussed briefly by categories of water, air, and solids in the following paragraphs. The majority of the residuals data are based on studies by Hittman, Battelle, and Teknekron.*

- It's usual to assume that water will be placed in evaporation ponds or recycled, so water pollutants are neglible. However, it is possible in areas where there is net rainfall that some discharge will occur. Potential sources of water effluent are from boiler blowdown, the raw gas cooling system, and weir overfill of the fresh water clarifier.

- Major air emissions (Table 9) may result from the sulfur recovery processes, the ammonia sulfate plant for the two BuMines processes and the Claus plant for the Koppers-Totzek processes (Hittman, 1975. Vol. II). Regional differences in sulfur dioxide emissions result from variations in the sulfur content of the coal. Northwest coal is lowest and northern Appalachian coal highest in sulfur content.

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*Hittman's data assume maximum environmental control; for example, it is assumed that water is recycled and that no effluent leaves the facility. The data have an error of less than 50%. The Battelle and Teknekron data generally are based on technologies that provide more limited environmental control and this is reflected in higher values for environmental residuals.

Table 9. Summary of low to intermediate Btu gasification pollutants

Process	Water	Air (tons per 10^{12} Btu's input) Sulfur Oxides[a]	Air (tons per 10^{12} Btu's input) Other	Solids[b] (tons per 10^{12} Btu's)
BuMines Atmospheric	0	12 to 40	0	3,500 to 7,000
BuMines Pressurized	0	14 to 40	0	3,500 to 7,000
Koppers-Totzek	0	18 to 41	12.5[c]	3,500 to 8,500
Lurgi	0	3.3	0	3,500

[a] Variation due to sulfur content difference in coal; only Northwest coal is used in the Lurgi calculation.

[b] Variation due to ash content difference in coal; only Northwest coal is used in the Lurgi calculation.

[c] Includes 40% particulates, 20% nitrogen oxides, 23% hydrocarbons, and 17% carbon monoxide.

Source: Hittman Associates, Inc. 1975. Environmental impacts, efficiency, and cost of energy supply and end use. Final report, Vol. II. Columbia MD.

- Solid waste volumes generated by low/intermediate Btu gasification processes range from 3,500 to 8,500 tons for each 10^{12} Btu's of coal processed (Table 9). These values include only ash removed from the combustor and depend upon the ash content of the coal. The lowest value is for Northwest coal, which has the lowest (6.4%) ash content, and the highest is for Central coal, which has the highest (17.3%) ash content. Because a typical low Btu gasification plant would produce an additional solid waste of about 5000 tons per 10^{12} Btu's amount daily, some or all of the waste require disposal in the mine. If the sulfur recovered in the process cannot be sold, it also may require disposal. The solid waste from a gasifier also contains small quantities of radioactive isotopes. For the agglomerating gasifier discussed by Teknekron (1973), these are 0.00076 curie of radium-226 and thorium-228 and -230 for each 10^{12} Btu's of coal gasified.

I.E.3.b. High Btu Gasification. Table 10 summarizes ranges of values for residuals calculated by Hittman (1975). A brief description of discharges to each medium follows:

- A plant synthesizing 250 mmcf of natural gas per day at 60% efficiency may emit 160×10^9 Btu's of waste heat per day. Presumably, most of this will be emitted to the atmosphere through the use of mechanical-draft, wet-cooling towers or dry cooling systems. These cooling towers will require 20 to 35 mgd of make-up water. Thus, in regions where water is scarce, all process wastewater and impounded runoff (about three million gallons per day) will be treated and used for cooling tower make-up. All blowdown streams are collected and sent to lined evaporative ponds. For this reason, water residuals are negligible, although settling ponds and process units could rupture or spill into streams or other water courses.

Wastewater treatment may also be required in areas where water is not recycled and where there is not a net evaporation. Characteristics of untreated wastewater are given in Table 11 for the Synthane gasifier unit and the entire Lurgi Process. Effluent characteristics from the Lurgi system assume the following treatment: three stages of tar-oil-water separation; filtration, phenol recovery, ammonia recovery in an ammonia still; and activated carbon treatment (Hittman, 1975. Vol. II).

- Air emissions may be produced from several byproduct streams, but most are from combustion of fuels in the plant boiler and the sulfur recovery plant. Stack discharges from the boiler usually are cleaned with an electrostatic precipitator for particulates and wet scrubbing system for gases. Emissions are given in Table 10 for five air pollutants. The range of values for any one process reflects variations due to area coal characteristics. In general, emissions are highest when Central area coal is used and lowest when Northwest coal is used.
- Solids generation varies regionally and primarily is a function of the ash content of the coal. Generally disposal requirements are least for Northwest coal (low in ash content) and greatest for northern Appalachian coal (high in ash content). For a high Btu gasification facility using Northwest coal, 3,700 tons of material (primarily ash) are generated for each 10^{12} Btu's of disposal from Central coal, and northern Appalachian coal use would produce about

Table 10. Summary of high Btu gasification residuals

Process	Water	Air (tons per 10^{12} Btu's coal processed)					Solids (tons per 10^{12} Btu's)	Total land[a] (acres)
		Particulates	Nitrogen oxides	Sulfur oxides	Hydrocarbons	Carbon monoxide		
HYGAS	(Recycled or treatment to meet standards (Table 11))	3- 7	60- 68	6-63	1	3.5	3,700-6,500	350
BI-GAS		3- 5	54- 63	14-81	1	3.0	3,800-6,800	350
Synthane		13-15	100-115	10-52	2	5.0	3,800-6,600	350
Lurgi		2- 4	73- 77	6-37	1	4.0	3,700-5,300	350
CO_2 Acceptor		3	38	62	0.5	2.0	8,600	350

[a] Land required is for coal storage, preparation, gasification plant facilities, and evaporation ponds. No additional requirement is assumed for buffer areas surrounding plant facilities (although they would probably be included in a commercial facility, on the order of 1,500 acres).

Source: Hittman Associates, Inc. 1975. Environmental impacts, efficiency, and cost of energy supply and end use. Final report, Vol. II. Columbia MD.

Table 11. Wastewater characteristics from two high Btu coal gasification processes

Parameter	Synthane Gasifier Vessel[a] (parts per million)	Lurgi Process[b]	
		Before Treatment (parts per million)	After Treatment (parts per million)
Thiocyanate	23	0	0
Cyanide	0.23	0	0
Ammonia	9,520	15,900	15.9
Sulfide	U	1,400	1.4
Suspended solids	140	600	33.5
Organics			
Phenols	6,000	9,960	0.498
Oil	0	1,100	15.4
Chemical oxygen demand	43,000	0	0

U = unknown.

Sources: [a] Forney, Albert J. 1974. Analyses of tars, chars, gases and water found in effluents from the synthane process. Bureau of Mines Technical Progress Report 76, Washington DC. Cited in University of Oklahoma, Science of Public Policy Program. 1975. Energy Alternatives: A comparative analysis.

[b] Hittman Associates, Inc. 1975b. Environmental impacts, efficiency, and cost of energy supply and end use. Final Report, Vol. II. Columbia MD , p. IV. Cited in University of Oklahoma, Science and Public Policy Program. 1975. Energy alternatives: A comparative analysis.

6,600 tons of solid wastes. For this reason, high Btu gasification plants may have to be mine mouth activities so that solid wastes can be returned to the mine for disposal.

In addition to ash, the CO_2 Acceptor process requires disposal of dolomite. Of the 8,600 tons shown in Table 10, spent dolomite is 6,700 tons or 78% of that total.

I.E.4. Pollution Control

Pollution control processes reduce adverse impacts that result when control is absent; however, the same processes can cause other kinds of impacts. The equipment used to control various waste streams in coal gasification facilities also can generate solid and liquid residual wastes which must be treated and properly disposed of. The sulfur removal processes may generate substantial quantities of sludge which must be disposed of. Likewise the biological processes generate sludges. There is no previous experience or data accumulated on this aspect.

I.F. REGULATIONS

Currently there are no national pollution standards which directly apply to atmospheric emissions or wastewater discharges from coal gasification plants. There are effluent limitations for the petroleum refining and by-product coke industries, which are sometimes compared to coal gasification. In addition, there are emission limits for the fossil fueled electric utility steam generation industry, which has similarities to the coal gasification industry. These effluent and emission limits are summarized in Table 12. It should be noted that, despite some similarities, the coal gasification facilities are quite different from byproduct coke, petroleum refining and utility generating facilities, and the limits developed by EPA for emissions and effluents from gasification plants may differ significantly from the values in Table 12.

Other pertinent air standards are the National Ambient Air Quality Standards, which specify the ambient air quality that must be maintained outside the plant boundary or within the boundary where the general public has access. Applicable Federal standards are shown in Table 13. Standards designated as primary are those necessary, with an adequate margin of safety, to protect the public health; secondary standards are those necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.

Table 12a. Adjusted new source performance standards for wastewater from petroleum refinery and byproduct coking facilities (from 40 CFR 419 and 420)

	Industry (kg pollutant per 10^{16} J, 30-day feedstock)[6]	
Pollutant	**Petroleum Refineries**	**Byproduct Coke**
BOD	99 - 436	205
TSS	62 - 278	104
Ammonia (as N)	20 - 172	104
Oil and Grease	30 - 101	104
Phenols	0.66 - 3.0	5.12
Sulfides	0.51 - 2.5	2.5

See Cleland, J.G. (1976)

Table 12b. Summary of Standards of Performance for Fossil-Fuel-Fired Steam Electric Generating Units for Which Construction is Commenced After September 18, 1978 (from 40 CFR 60)

Pollutant	Emission Limit
Sulfur Dioxide	520 ng/J (1.2 lb/10^6 Btu)[1]
Nitrogen Oxides	260 ng/J (0.60 lb/10^6 Btu)[2,3]
Particulate Matter	13 ng/J (0.03 lb/10^6 Btu)[4]
Opacity	20 percent[5]

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1. For coal, a 90 percent reduction in potential SO_2 emissions is required at all times except when emissions to the atmosphere are less than 260 ng/J (0.60 lb/10^6 Btu). When SO_2 emissions are less than 260 ng/J (0.60 lb/10^6 Btu), a 70% reduction in emissions is required.
2. Except: (a) the limits for coal derived gaseous, liquid and solid fuels, and for subbituminous coal, are 210 ng/J (0.50 lb/10^6 Btu); (b) the limit for any fuel containing more than 25% (by weight) lignite mined in North Dakota, South Dakota or Montana and combusted in a slag tap furnace is 340 ng/J (0.80 lb/10^6 Btu); (c) Any fuel containing more than 25% (by weight) coal refuse is exempt from NOx standards. Other deviations from the 260 ng/J (0.60 lb/10^6 Btu) limit for liquid and gaseous fuel are in 40 CFR 60.44a.
3. For coal, a 65 percent reduction in potential nitrogen oxide emissions is required.
4. For coal, a 99 percent reduction in potential particulate emissions is required.
5. Except for one 6-minute period per hour of not more than 27% opacity.
6. Assumes heating values of 6.5 mmBtu/bbl for crude oil and 12,000 Btu/lb for coal, with a coke yield of .69 lb coke/lb coal.

Table 13. Summary of National Ambient Air Quality Standards (from 40 CFR 50)

Emission	Standard Primary	 Secondary
Sulfur dioxide	80 micrograms/m^3 annual arithmetic mean	1,300 micrograms/m^3 maximum 3-hour concentration*
	365 micrograms/m^3 maximum 24-hour concentration*	
Particulate matter	75 micrograms/m^3 annual geometric mean	150 micrograms/m^3 maximum 24-hour concentration*
	260 micrograms/m^3 maximum 24-hour concentration*	60 micrograms/m^3 annual geometric mean (as guide in assessing implementation plans)
Hydrocarbons	160 micrograms/m^3 (0.24 ppm) maximum 3-hour concentration *	160 micrograms/m^3 (0.24 ppm) maximum 3-hour concentration*
Nitrogen dioxide	100 micrograms/m^3 annual arithmetic mean	100 micrograms/m^3 annual arithmetic mean
Ozone	235 micrograms/m^3 (0.12 ppm) maximum 1-hour concentration*	235 micrograms/m^3 (0.12 ppm) maximum 1-hour concentration*
Carbon monoxide	10 mg/m^3 (9 ppm) maximum 8-hour concentration*	10 mg/m^3 (9 ppm) maximum 8-hour concentration*
	40 mg/m^3 (35 ppm) maximum 1-hour concentration*	40 mg/m^3 (35 ppm) maximum 1-hour concentration*
Lead	1.5 micrograms/m^3 maximum calendar quarterly average	1.5 micrograms/m^3 maximum calendar quarterly average

*The maximum allowable concentration may be exceeded for the prescribed period once each year without violating the standard.

In 1974, the Environmental Protection Agency (EPA) issued regulations for the prevention of significant deterioration of air quality (PSD) under the 1970 version of the Clean Air Act (Public Law 90-604). These regulations established a plan for protecting areas that possess air quality which is cleaner than the National Ambient Air Quality Standards (NAAQS). Under EPA's regulatory plan, clean air areas of the Nation could be designated as one of three "Classes." The plan permitted specified numerical "increments" of air pollution increases from major stationary sources for each class, up to a level considered to be "significant" for that area. Class I provided extraordinary protection from air quality deterioration and permitted only minor increases in air pollution levels. Under this concept, virtually any increase in air pollution in the above pristine areas would be considered signficant. Class II increments permitted increases in air pollution levels such as would usually accompany well-controlled growth. Class III increments permitted increases in air pollution levels up to the NAAQS.
Sections 160-169 were added to the Act by the Clean Air Act Amendments of 1977. These amendments adopt the basic concept of the above administratively developed procedure of allowing incremental increases in air pollutants by class. Through these amendments, Congress also provided a mechanism to apply a practical adverse impact test which did not exist in the EPA regulations.

The PSD requirements of 1974 applied only to two pollutants: total suspended particulates (TSP) and sulfur dioxide (SO_2) (See Table 14). However, Section 166 requires EPA to promulgate PSD regulations by 7 August 1980 addressing nitrogen oxides, hydrocarbons, carbon monoxide, and ozone utilizing increments or other effective control strategies. For these additional pollutants, States may adopt non-increment control strategies which, if taken as a whole, accomplish the purpose of PSD policy set forth in Section 160.

Whereas the earlier EPA regulatory process had not resulted in the Class I designation of any Federal lands, the 1977 Amendments designated certain Federal lands Class I. All international parks, national memorial parks and national parks exceeding 6,000 acres, are designated Class I. These 158 areas may not be redesignated to another class through State or administrative action. The remaining areas of the country are initially designated Class II. Within this Class II category, certain national primitive areas, national wild and scenic rivers, national wildlife refuges, national seashores and lakeshores, and new national park and wilderness areas which are established after 7 August 1977, if over 10,000 acres in size, are Class II "floor areas" and are ineligible for redesignation to Class III.

Although the earlier EPA regulatory process allowed redesignation by the Federal land manager, the 1977 amendments place the general redesignation responsibility with the States. The Federal land manager only has an advisory role in the redesignation process, and may recommend redesignation to the appropriate State or to Congress.

In order for Congress to redesignate areas, proposed legislation would be introduced. Once proposed, this would probably follow the normal legislative process of committee hearings, floor debate, and action. In order for a State to redesignate areas, the detailed process outlined in Section 164(b) would be followed. This would include an analysis of the health, environmental, economic, social, and energy effects of the proposed redesignation to be followed by a public hearing.

Table 14. Nondeterioration increments by air quality classification

Pollutant	Class I ($\mu g/m^3$)	Class II ($\mu g/m^3$)	Class III ($\mu g/m^3$)	Class I exception ($\mu g/m^3$)
Particulate matter:				
Annual geometric mean	5	20	37	19
24-hour maximum	10	37	75	37
Sulfur dioxide:				
Annual arithmetic mean	2	20	40	20
24-hour maximum	5*	91	182	91
3-hour maximum	25*	512	700	325

*A variance may be allowed to exceed each of these increments on 18 days per year, subject to limiting 24-hour increments of 36 $\mu g/m^3$ for low terrain and 62 $\mu g/m^3$ for high terrain and 3-hour increments of 130 $\mu g/m^3$ for low terrain and 221 $\mu g/m^3$ for high terrain. To obtain such a variance requires both State and Federal approval.

Source: Clean Air Act Amendment of 1977 (42 USC 7401 et seq.) H.R. 6161, Public Law 95-95, 95th Congress: August 7.

Class I status provides protection to areas by requiring any new major emitting facility (generally a large point source of air pollution--see Section 169(1) for definition) in the vicinity to be built in such a way and place as to insure no adverse impact on the Class I air quality related values.

The permit may be issued if the Class I increment will not be exceeded, unless the Federal land manager demonstrates to the satisfaction of the State that the facility will have an adverse impact on the Class I air quality related values.

The permit must be denied if the Class I increment will be exceeded, unless the applicant receives certification from the Federal land manager that the facility will not adversely affect Class I air quality related values. The permit may be issued even though the Class I increment will be exceeded (Up to the Class I increment -- see Table 14).

In the absence of Federal effluent limitations for the coal gasification industry, the selection of limitations in NPDES permits will be made on the basis of receiving water quality standards and applicable State and local standards. It appears likely that those setting NPDES limitations will take into account the Federal effluent guidelines and standards from related industries, as discussed above, in their determination of standards to preserve existing water quality.

Moreover, coal gasification facilities will depend largely on surface mined coal; therefore, the standards established under the Federal strip mining legislation (PL 95-87) also are pertinent. Table 15 lists recommended NSPS for coal storage, refuse storage, coal preparation, and acid and alkaline mine drainage (mining related regulations are discussed in detail in a separate appendix, Surface Coal Mining).

Table 15 Nationwide performance standards for wastewater discharged after application of the best available demonstrated control technology by new sources in the coal mining point source category. The limitations are not applicable to excess water discharged as a result of precipitation of snow melt in excess of the 10-year, 24-hour precipitation event (40 CFR 434; 44 FR 9:2586-2592, 12 January 1979). Units are milligrams per liter (mg/l) except as otherwise indicated.

			BITUMINOUS, LIGNITE, AND ANTHRACITE MINING			
	Coal Preparation Plants And Associated Areas		Acid or Ferruginous Mine Drainage[1]		Alkaline Mine Drainage[1]	
Parameter	1-day Maximum	Average of 30 consecutive daily values	1-day Maximum	Average of 30 consecutive daily values	1-day Maximum	Average of 30 consecutive daily values
Total suspended solids	70.0	35.0	70.0[2]	35.0[2]	70.0[2]	35.0[2]
Total iron	6.0	3.0	6.0	3.0	6.0	3.0
Total manganese	4.0	2.0	4.0	2.0		
pH (pH units)	range 6.0-9.0		range 6.0-9.0		range 6.0-9.0	

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[1] Drainage which is not from an active mining area (for example, a regraded area) is not required to meet the stated limitations unless it is mixed with untreated mine drainage that is subject to the limitations.

[2] Total suspended solids limitations do not apply in Colorado, Montana, North Dakota, South Dakota, and Wyoming. In these states, limitations for total suspended solids are determined on a case by case basis.

II. IMPACT IDENTIFICATION

II.A. PROCESS WASTES

II.A.1. Air Emission Sources

The impact of coal gasification plant emissions to the atmosphere vary and depend largely on:

- Gasifier design and operating parameters
- Type and source of coal used for gasification
- Coal gas treatment steps employed
- Quantity and ultimate use of the product gas

It should be noted that the coal gasification process essentially is a closed chemical system and that major sources of airborne emissions generally are fugitive in nature. Table 16 summarizes such emission sources. Each of the major sources of air emissions which, at a minimum, will require evaluation in the EID are discussed below.

II.A.1.a. Coal Storage and Preparation. Coal storage and preparation areas are potential sources of significant quantities of dust. Coal storage piles have large exposed surface areas which can be sources of coal dust and fine particulates. Coal conveying, crushing, grinding, and drying operations also are potentially significant sources of particulate emissions. In addition, consideration should be given to the possibility of spontaneous combustion of coal storage piles, which results in the emission of noxious fumes.

II.A.1.b. Gasification Processes. Normally no major atmospheric emissions are expected from the gasification processes. However, the emission of dust, from handling dry ash or char from the gasifier, and of odor, from the ash and char quench systems can occur and should be addressed in the EIA.

II.A.1.c. Acid Gas Removal. Acid gas removal processes are potential sources of atmospheric emissions (particularly H_2S, COS, and thiophenes).

II.A.1.d. Methanation. During methanation no air emissions are expected for normal operations; however, during process startups and shutdowns emissions can occur. Of particular significance is the potential for formation and atmospheric release of nickel carbonyl.

II.A.1.e. Compression. There are no significant atmospheric emissions directly associated with this operation. However, a large amount of energy is required during the compression process and the energy source emissions from power production must be assessed.

II.A.1.f. Sulfur Recovery. Sulfur recovery processes are potentially significant sources of atmospheric sulfur emissions (in particular, H_2S, SO_2, COS, and CS_2).

Table 16. Process stream characteristics for coal gasification and probability ratings (low, medium, high) for fugitive air emissions by process

Process Name	Process stream characteristics					
	Pressure	Temperature	Potentially hazardous volatiles	Corro- siveness	General house- keeping	Potential for hazardous fugitive emissions
Coal preparation	low	low	med	low	poor	med
Oxygen blown gasification	high	high	high	med-high	med	med-high
Quenching and cooling	low	med-high	high	high	med	med-high
Tar separation	low	low	high	med	poor	high
Shift conversion	high	high	low	low	good	low-med
Phenol recovery	low	med	high	med	med	med
Acid gas removal	low	low	high	low	med	med
Methanation	high	high	med	low	good	med
Further gas purification	low	low	med	low	med	med
Sulfur recovery	low	low	med	low	med	low-med
Air blown gasification	high	high	high	med-high	med	med-high
Storage	low	low	med	low	med	med

Source: Adapted from Cavanaugh, G.D. et al. 1977. Potentially hazardous emissions for the extraction and processing of coal and oil. Prepared for US-EPA (EPA GSO/2-75-038), Research Triangle Park NC.

II.A.1.g. Ash and Solids Disposal. Normally there should be very little air contamination from solids disposal; however, odors may occur when ash is quenched, and dust may be emitted when dry solids are handled. Plans for the disposal of solids should be described in the EID.

II.A.1.h. Emissions from Ancillary Facilities. In addition to those facilities physically involved in the coal preparation and gasification phases, other separate, but interrelated, components are required for full plant operation. These may include such operations as:

- Steam generation and distribution
- Oxygen production
- Power generation and distribution
- End product distribution (via pipeline, etc.)

Although these components serve an important supporting role in the gasification process, their characterisitics and associated impacts are discussed in separate guidelines. They can be major contributors to emissions.

II.A.2. Characteristics of Potential Atmospheric Emissions

The potential atmospheric emissions from the gasification of coal include the major pollutants associated with coal and char combustion (particulates, NO_x, and SO_2 emissions), as well as materials which may be emitted from the various operations in the gasification process described above. A summary of major waste streams (air, water, solids), their principal components, source, disposition, and associated processes are presented in Table 17. A list of possible pollutants, which include particulates, metals, gases, polynuclear aromatics, and other organics, also is presented in Table 17. Of particular concern, because of their potentially adverse environmental and health effects, are:

- Emissions of trace elements present in coal
- Trace compounds formed in the gasification process
- Sulfur and carbonyl compounds.

II.A.2.a. Trace Elements in Coal. The trace elements present in the processed coal must be considered as potential atmospheric emissions. The content of trace elements in coals from different regions and of different types is highly variable (see Table 18). Therefore, the potential for trace element emissions will vary with the type of coal used as well as the type of gasification process used. Considerable data on trace elements in coals are available from the U.S. Bureau of Mines and the U.S. Geological Survey; however, the composition of particular coal must be determined because most of the data available are not site specific.

Little is known about the fate of trace metals in coal gasification. Trace elements of particular concern, because of their potential toxicity and volatility, include mercury, silenium, arsenic, lead, cadmium, beryllium, and fluorine. During coal combustion, trace elements volatilize in the firebox and then recondense into fine particulates which are emitted with the flue gas; often these particles are so fine that they are difficult to collect with particulate control equipment. Also during coal gasification, volatilization is enhanced because of the reducing atmosphere in which the process takes place.

Table 17. Nature and sources of major waste streams associated with the gasification of coal

WASTE STREAM	PRINCIPAL COMPONENTS	SOURCES	DISPOSITION	PROCESS
Coal dust	Carbon particles	Feedstock crushings and grinding	Containment and recovery	Cyclone separators, bag filters, enclosure
Stack gas	CO_2, SO_2, N_2, O_2	Steam generation Stack gas cleanup	Treatment/discharge	Wellman-Lord, limestone injection, lime scrubbing, catalytic oxidation, double alkali, Citrate
	Nitrogen	Oxygen generation	Discharge	
Acid gas	H_2, CO_2, CH_2, COS, H_2S, N_2	Product of shift conversion	Sulfur recovery	H_2S can be selectively removed from a gas stream by a rectisol hot potassium carbonate, Sulfinol, MEA, DIPA, or similar process. Claus and Stretford processes recover elemental sulfur from H_2S rich streams Tail gases from these units can be treated by incineration, Beavon, Wellman-Lord, or SCOT process.
Exhaust emissions	CO, HC, NO_x, particulate	Automobile traffic	Discharge	
Runoff leachings	Pyrites, sediment, oil, organic matter Sediment	Feedstock storage Ash ponds Land surface	Treatment/utilization Discharge	Neutralization Settling
Wastewater	Dissolved salts NH_3, phenols, cyanide Thiocyanate, BTX	Water treatment Gasification Product of shift conversion Methanation	Treatment/utlization Treatment and reuse	Coagulation Chevron, Phenosolvan, Phosam, biological oxidation
Blowdown	Dissolved salts	Boilers/cooling towers	Treatment and reuse	Chevron, Phenosolvan, Phosam, bio. oxidation
Cooling water	Heat	Heat exchangers	Utilization discharge	Waste heat recover, cooling towers
Sanitary sewage	Organic/nitrogen compounds	Washrooms	Treatment and utlization	Biological oxidation
Rocks and debris		Feedstock cleaning	Disposal/utilization	Landfill/construction material

(continued on next page)

Table 17. Nature and sources of major waste streams associated with the gasification of coal (Concluded)

WASTE STREAM	PRINCIPAL COMPONENTS	SOURCES	DISPOSITION	PROCESS
Tar	COD, DS, SS, CO, CH_4, Phenols, NH_3, HCN, Thiocyanate, H_2S	Gasification	Utilization	Conversion to oil, direct gasification
Char	Fixed carbon, sulfur	Gasification	Disposal/utilization	Gasification, desulfurization, direct combustion
Ash	Inert residue	Gasification, steam generation	Disposal/utilization	Landfill/incorporation in construction materials
Spent catalysts	Cobalt, molybdenum, iron	Shift conversion	Treatment and recovery	
	Bauxite	Sulfur recovery	Treatment and disposal	Oxidation
	Nickel	Methanation	Treatment and disposal	
Spent purifying media	Iron or zinc oxide	Final purification	Treatment and disposal	Oxidation
Sludge	Spent carbon	Final purification	Disposal	
	Sulfites	Stack gas cleanup	Treatment and disposal	
Refuse	Solids, biomass	Wastewater[a] treatment	Treatment and disposal	Dewatering, oxidation, landfilling
		Work areas	Treatment and disposal	Incineration, landfilling

Source: U.S. Environmental Protection Agency. 1974. Emissions from processes producing clean fuels. EPA-450/3-73 028.

Table 18. Ranges of chemical constituents of representative U.S. coals

Item	Range (%)	Item	Range (ppm)
Major constituents:		Trace elements:	
C	55.2 - 80.1	As	0.5 - 93.0
H	4.0 - 5.8	B	5.0 - 224.0
N	0.8 - 1.8	Be	0.2 - 4.0
O	4.2 - 16.0	Br	4.0 - 52.0
		Cd	0.1 - 65.0
Major characteristics:			
		Co	1.0 - 43.0
Air dry loss	1.4 - 16.7	Cr	4.0 - 54.0
Moisture	0.1 - 20.7	Cu	5.0 - 61.0
Volatility	18.9 - 52.7	F	25.0 - 143.0
C, fixed	34.6 - 65.4	Ga	1.1 - 7.5
Ash	2.2 - 25.8	Ge	1.0 - 43.0
		Hg	0.02 - 1.6
Minor constituents:			
		Mn	6.0 - 181.0
Al	0.42 - 3.0	Mo	1.0 - 30.0
Ca	0.05 - 2.7	Ni	3.0 - 80.0
Cl	0.01 - 0.5	P	5.0 - 400.0
Fe	0.3 - 4.3	Pb	4.0 - 218.0
K	0.02 - 0.4	Sb	0.2 - 8.9
Mg	0.01 - 0.2	Se	0.4 - 7.7
Na	0.00 - 0.2	Sn	1.0 - 51.0
Si	0.58 - 6.1	V	11.0 - 78.0
Ti	0.02 - 0.2	Zn	6.0 - 535.0
S, organic	0.3 - 3.1	Zr	8.0 - 133.0
S, pyritic	0.06 - 3.8		
S, SO_4	0.01 - 1.1		
S, total	0.4 - 6.5		
S, X-ray	0.5 - 5.4		

Source: Ruch, R. R., H. J. Gluskoter, and N. F. Shimp. 1974. Occurrence and distribution of potentially volatile trace elements in coal. EPA-650/2-74/054. Illinois State Geological Survey.

Some elements were likely to appear in groups; that is, when one was higher in concentration, the others in the groups were higher. The groups were:

- Zinc (Zn), cadmium (Cd)
- Arsenic (As), cobalt (Co), copper (Cu), nickel (Ni), lead (Pb), antimony (Sb)
- Potassium (K), titanium (Ti), aluminum (Al), silicon (Si)
- Manganese (Mn), calcium (Ca)
- Sodium (Na), chlorine (Cl)

Germanium (Ge), beryllium (Be), and boron (B) are likely to be associated with the organic part of the coal, whereas mercury (Hg), zirconium (Zr), Zn, As, Cd, Pb, Mn, and molybdenum (Mo), are likely to be associated with the inorganic part of the coal. Because equal cleaning processes tend to separate the inorganic from the organic part of the mined coal, such processes will have a significant effect on the composition of the feed to a coal gasification process.

II.A.2.b. Trace Compounds Formed in Processing. Little information is available as to concentrations of trace compounds in atmospheric emissions from coal gasification. Compounds which may form include the polynuclear aromatics and other organic materials shown in Table 19. Again, the formation of many of these compounds is promoted by the reducing atmosphere in which gasification takes place. Many of these compounds are of particular concern because they are carcinogenic or otherwise toxic.

II.A.2.c. Sulfur Compounds. Sulfur which is removed from the product gas generally is reclaimed in the form of elemental sulfur. However, during the removal and recovery processes there is a potential for atmospheric emissions of sulfur in the form of SO_2, thiophene, H_2S, COS, CS_2, and other reduced sulfur compounds. Many of the reduced sulfur compounds are of concern because they are potentially toxic or odorous.

II.A.2.d. Carbonyl Compounds. Regeneration of catalysts used in coal gasification (particularly in methanation) is a potential source of nickel, cobalt, and iron carbonyl emissions. These are of particular concern because of their high toxicity.

In summary the permit applicant should include, at a minimum, the following information relative to air emissions in the EID.

- Volumes, concentrations, and temperatures of each air emission point
- Conditions of discharge point including height and location
- Control technology proposed for each emission point including efficiency
- Fugitive emissions including composition and quantity
- Control technology proposed to minimize fugitive emissions
- Distribution of trace elements in feed coal
- Projected ambient air concentrations at fence line and in neighboring areas of high receptor incident.

II.A.3. Water Effluent Sources

Gasification plants are not major sources of waterborne effluents. Also

Table 19. Potentially hazardous substances suspected present in coal conversion plant process streams

Chemical classification	Compound	Phase
Acids and anhydrides	Maleic acid	liquid
	Cresylic acid	liquid
	Sulfuric acid	liquid
	Anthraquinone disulfuric acid	liquid
Alcohols	Aliphatic alcohols	liquid
	Aromatic alcohols	liquid
Amines	Diethylamines	gas
	Methylethylamines	gas
	Ammonia	gas/liquid
Inorganic salts	Ammonia sulfate	liquid
Carbonyl compounds	Ketones	gas/liquid
	Aldehydes	gas/liquid
Combustion cases	Carbon monoxide	gas
	Sulfur oxides	gas
	Nitrogen oxides	gas
Heterocyclics	Pyridines	gas/liquid
	Pyrroles	gas/liquid
	(Mono) Benzofurans	gas
Hydrocarbons	Benzene	gas/liquid
	Toluene	gas/liquid
	Xylene	gas/liquid
	Ethylcyclopentane	gas
	Decane	gas
	Undecane	gas
	Dodecane	gas
	Naphthalene	gas
	Ethylbenzenes	gas
	Propylbenzenes	gas
	Ethyltoluenes	gas
	Trimethylbenzene	gas
	Olefins	gas
Phenols	Phenols	gas/liquid
	Dimenthyl phenol	liquid
	Cresols	gas/liquid
	Xylenols	gas/liquid
	Phenyl phenols	gas
	Alkyl phenols	gas
	Alkyl cresols	gas
	Ethylphenols	gas
	Propylphenols	gas
	Methylethylphenol	gas
	Indanols	gas
	Beta-naphthol	gas
	Pyrocatechol	gas
	Resorcinol	gas
	Methyl resorcinol	gas

Source: Cavanaugh, G.D., et al. 1975. Potentially hazardous emissions for the extraction and processing of coal and oil. USEPA 650/2-75-038, Research Triangle Park NC.

there are few data on concentrations and volumes of effluents because there are no commercially producing coal gasification plants in the U.S. In general, waste liquids are evaporated or recirculated. Wastewater characteristics from two high Btu coal gasification processes are presented in Table 11. The major sources of these effluents are given below.

II.A.3.a. Coal Preparation Runoff and Wet Scrubber Dust Collector Effluent.

Effluents from these sources contain suspended fines, sulfur compounds, and heavy metals.

II.A.3.b. Gasifiers. Liquids from gas cooling and from the waste heat boilers normally are used as quench water in the tar separator prior to treatment.

II.A.3.c. Sulfur Plant Recirculation Water Purge. Discharges depend on the nature of the sulfur reclamation system used. Discharges from the Claus process largely are waste oils; however, the liquid wastes from the Stretford process include anthraquinone disulfonate, metavanadate, citrate, thiosulfate, thiocyanate, and sodium salts.

II.A.3.d. Tar Separation. The purge water from the tar separation unit contains ammonia, phenol, and tars as well as reduced sulfur compounds.

II.A.3.e. Water Treatment and Boiler Blowdown. The blowdown from boilers, cooling towers, and water treatment facilities include waters with high concentrations of dissolved solids.

To evaluate liquid wastestreams adequately, the EID should provide, at a minimum, the following information:

- Existing water quantity and quality data (surface and subsurface)
- Sources and volumes of all wastewater streams
- Occurrence and duration of wastewater flows
- Composition of wastewaters
- Nature and volume of irregular flows including surface drainage
- Proposed measures to reduce or avoid potential environmental impact.

II.A.4. Solid Waste Sources

There are several sources of solid wastes from coal gasification facilities. The major source is the gasifier; composition and quantity of this waste is largely dependent on the coal that enters the gasifier vessel. Other solid wastes include flyash and sludge which are collected from the various processes, as shown in Table 20.

These solids may contain significant amounts of leachable heavy metals and organics which could contaminate the environment if not treated and disposed of properly.

To evaluate the potential for impact from solid waste generation, the applicant should provide at least the following information in the EID:

Table 20. Solid wastes from coal gasification facilities*

Source	Quantity (tons/day)
Quenched ash from gasifiers	1,550
Steam generator bottom ash	38
Steam generator fly ash	114
Intake water clarifier sludge	2
Biotreatment sludge	4
Miscellaneous fly ash	150
Spent catalysts	2

*Plant size, 7.08×10^6 m^3/d (250 mmscf/day).

Source: Hittman Associates, Inc. 1975. Environmental effects, impacts, and issues related to large scale coal refining complexes. Available from National Technical Information Service, NTIS FE-1508-T2. Washington DC.

- Source and quantity of solid wastes generated
- Composition of solid wastes generated
- Composition of possible leachate from solid wastes
- Proposed measures to handle and dispose of solid wastes

II.B. TOXICITY AND POTENTIAL FOR ENVIRONMENTAL DAMAGE FROM SELECTED POLLUTANTS

II.B.1. Human Health Impacts

A coal gasification plant's airborne and waterborne emissions may contain substances which could have serious impacts on human health. Both heavy metals and a variety of complex hydrocarbons including polycyclic organics may be emitted from coal gasification facilities (see Table 19). However it should be noted that coal gasification is a closed process and therefore the emission problems will be considerably less than with coking plants. Because of lack of experience in the U.S., the quantities and significance of emissions are not well established nor understood and, therefore, the background data and documentation relative to specific health impacts are slight. A complete review of the literature is now available (ORNL 1977). Some evaluations can be made by review of evidence gathered for coking plants, electric generating stations, and other facilities that emit similar constituents. The following describes the health-related effects of selected pollutants.

II.B.1.a. Carcinogens. Correlations have been drawn repeatedly between exposures of coke oven workers to soot, coal dust, and other coal combustion or pyrolysis products and an elevated incidence of cancer of the lung and urinary tract as well as other vital locations (National Institute for Occupational Safety and Health 1975). Reports of increased skin cancer in workers at coal hydrogenation plants also suggest an elevated carcinogenic risk. Those exposed to the process had a skin cancer incidence between 16 and 37 times higher than that of the regional and national populace (Sexton 1975).

Other factors that may be of consequence are the carbonization temperature, the type of retort, and the time of exposure to the tars (National Institute for Occupational Safety and Health 1975; Doll 1974; Kawai 1967). During the quenching and cooling of the offgas and the tar separation, the worker may be exposed to selenium, benzene, nickel, and lead in the emissions from the tar separation unit. Other suspected carcinogens that may be in the emissions include arsenic, cadmium, beryllium, chrysene, benzo(e)pyrene, benz(a)anthracene, and benzo(a)pyrene. If methanation occurs during the reaction, then nickel carbonyl and benzene may be among the emissions (Cavanaugh 1975). If coal ash is taken directly from the process to the environment, it could emit known carcinogens to the environment.

II.B.1.b. Sulfur Dioxide and Hydrogen Sulfide. The impact of high concentrations of sulfur dioxide and sulfates (especially in the presence of particulates), has been well documented (USEPA 1970).

Likewise hydrogen sulfide is strongly irritating to the respiratory organs. At high concentrations (1,000 mg/m^3), hydrogen sulfide is extremely toxic and may paralyze the brain center that controls the respiratory movements (Cavanaugh 1975).

Table 21. Possible health problems associated with trace metals

Metal or metal compound	Health problems	Reference
Nickel carbonyl	Suspected carcinogenesis	(Sunderman and Donnelly 1965) (Cavanaugh 1975)
Antimony, arsenic, cadmium, cobalt, copper, iron, lead, magnesium, manganese, tin, and zinc oxides	Fume fever	(Waldbott 1973)
Nickel	Nasal cancers	(Gilman and Ruckerbauer 1963)
Cadmium	Prostate cancer	(Pott 1965); (Kipling and Waterhouse 1967)
Chromium and compounds	Carcinogenesis	(Hueper 1961)
Berylium and compounds	Carcinogenesis	(Reeves et al. 1967); (Wager et al. 1969)
	Poisoning	(Nishimuta 1966)
Arsenic	Cancer of the skin Poisoning	(Wickstrom 1972) (Lee and Fraumeni 1969)
Cobalt	Carcinogenesis	(Gilman and Ruckerbauer 1963)
Lead and compounds	Nasal cancers	(Zawirsica and Medras 1968)
	Kidney damage	(Zollinger 1953)
Mercury and compounds	Mutagenic and teratongenic effects	(D'Itri 1972)
Vanadium	Inhibition of lipid formation	(Stokinger 1963)

II.B.1.c. Nitrogen Compounds. Nitrogen oxides are a problem only where coal is burned as a fuel. Nitrogen oxides are pulmonary irritants and may impair the ability of the lungs to clear inhaled infectious organisms. Exposure to nitrogen dioxide also can be corrosive to the mucous lining of the lungs. At high concentrations, it may cause pulmonary edema and even death, while chronic exposure may produce emphysema, polyeythamia, and leukocytosis. In addition, nitrogen oxides have been shown to be involved in the formation of photochemical smog (USEPA 1971c).

II.B.1.d. Hydrocarbons. Hydrocarbons play a vital role in the formation of photochemical smog (USEPA 1971b).

II.B.1.e. Carbon Monoxide. The toxicity of carbon monoxide is associated with its reactions with hemoproteins. It is anticipated that there will be no increase of ambient concentrations beyond national ambient air standards and, therefore, it is expected that no adverse impact will be associated with the emission of carbon monoxide from coal gasification plants (USEPA 1971a).

II.B.1.f. Ammonia. Ammonia is a highly irritating gas with a strong, pungent odor. It forms ammonium hydroxide when it comes in contact with the moisture of the throat and bronchi. Ammonium hydroxide is caustic, but it is not a threat to human health. Extremely high concentrations, however, (1,700-4,500 mg/m^3) can produce pulmonary edema (Waldbott 1973).

II.B.1.g. Trace Metals. Among the possible health problems associated with trace metals are those shown in Table 21. The appropriate references should be reviewed by the permit applicant to ascertain the significance of the impact as associated with trace metal emissions from the proposed coal gasification facility.

To adequately evaluate potential impacts to human health the applicant should include at least the following information in the EIA:

- Analysis of coal to be used in the gasification process
- Projection of emissions of potentially toxic substances (volumes and duration)
- Analysis of sensitive receptors (by use of isopleths or other suitable technique)
- Projection of ground level maximum concentrations of potentially hazardous substances
- Description of proposed measure to avoid or reduce potential adverse effects from toxic materials.

II.B.2. Biological Impacts

The biological environment also may be affected by certain pollutants, especially heavy metals, which are toxic to many terrestrial and aquatic organisms, both complex and simple.

The potential impacts on terrestrial and aquatic biota may be categorized by the following waste streams and pollutants:

- Air pollutants - emissions of heavy metals, sulfur dioxide, and particulates.
- Wastewater discharges - water pollutants such as heavy metals and toxic organics from leaching of solid wastes, infiltration, or leaks from stabilization/evaporation ponds, cooling tower drift and atmospheric washout of air pollutants.
- Solid wastes - stockpiling and dumping of slags and other solid wastes.

At a minimum the following information should be developed in the EID to assess adequately the magnitude and significance of impacts to biological resources:

- Discharges and sinks for specific toxic materials such as heavy metals and organics (include information on volume, duration, and time of discharges)
- Characteristics of the aquatic and terrestrial biota of the impact area (species composition, diversity, abundance, densities, importance values)
- Determination of tolerance or sensitivity thresholds for selected species of plants and animals in the impact area
- Proposed measures to avoid or reduce adverse impacts to biological communities.

II.C. OTHER IMPACTS

II.C.1. Raw Materials and Byproduct Handling

The principal area of concern with respect to handling raw materials is with the coal. Potential environmental impacts associated with coal handling result from runoff from coal storage areas and from dust generated. Coals may contain various elements (Table 22) which may enter thin films of water that exist when the coal is damp and exposed to air. Rainfall will wash off this film and produce an initial runoff that is often acid and usually high in concentrations of iron, copper, and/or zinc, and that has objectionable amounts of suspended solids and organic material. The acid and reducing nature of the runoff is caused by the sulfur compounds in the coal; these characteristics increase the solubility of many metallic impurities.

In addition to possible impacts associated with coal handling and processing, the transport of byproducts from coal gasification plants may represent a significant environmental impact in the form of spills, ruptures, and so forth; for example, the shipment of byproducts such as elemental sulfur and coal tars, could pose a spill hazard. Certain waste products (liquors, ash, slag, etc.) also may require transport from the plant for final disposal which could result in spills and contamination. Usually these materials only have a low or moderate toxicity rating but spills are not desirable aesthetically and the potential does exist for degradation of water quality as a result of direct spillage or indirect contamination through leaching. Therefore the applicant should project the probability of such accidents occurring and disclose any plans that are proposed to handle these potential hazards.

Table 22. Coal pile drainage water: Analyses from nine coal-fired steam electric generating plants.

Contaminant	Analyses (mg.1) Range	Average of three plants, high sulfur coal	One plant low sulfur coal
Alkalinity	0 - 82	0	24
Acidity	8 - 27,810	24,800	6
BOD	0 - 10	NA	NA
COD	85 - 1,099	NA	NA
Total solids	1,330 - 45,000	NA	NA
Total dissolved solids	247 - 44,050	26,500	NA
Total suspended solids	22 - 3,302	NA	NA
Ammonia (N)	0 - 1.8	NA	NA
Nitrate (N)	0.3 - 2.2	NA	NA
P	0.2 - 1.2	NA	NA
Turbidity	3 - 505	NA	6
Hardness ($CaCO_3$)	130 - 1,850	NA	NA
Sulfate	133 - 21,920	16,000	NA
Chloride	4 - 481	NA	NA
Al	825 - 1,200	1,012	NA
Cr	0 - 16	8	NA
Cu	1.6 - 3.4	2.6	NA
Fe	0.1 - 93,000	48,800	1
Zn	0.01 - 23	18	NA

NA = Not available.

Source: US Environmental Protection Agency. 1974. Development document for effluent guidelines and new source performance standards for the steam electric power generating point source category. EPA 440/1-74 029-a. Effluent Guidelines Division, Office of Water and Hazardous Materials, Washington DC.

II.C.2. Site Preparation and Plant Construction

The environmental effects of site preparation and construction of new coal gasification facilities are common to most major land disturbing activities. Although erosion, dust, noise, vehicular traffic and emissions, and some loss of wildlife habitats are to be expected, they also should be minimized through good construction practices wherever possible. At present, however, neither the quantities of the various pollutants resulting from site preparation and construction nor their effects on the integrity of aquatic and terrestrial ecosystems has been studied sufficiently to permit broad generalizations. Therefore in addition to the impact assessment framework provided in the EPA document, Environmental Impact Assessment Guidelines for Selected New Source Industries, a suggested checklist of important study items is presented in Table 23 for further guidance to the applicant. The basic components of site preparation and plant construction outlined in the table include preconstruction, site work, permanent facilities, and ancillary facilities. At this time only potentially significant areas of impact are presented in the checklist but a system of values and significance should be acquired at an individual site or for a region. The permit applicant also should tailor all proposed conservation practices to the specific site(s) being considered in order to account for and to protect certain site specific or endangered species, archaeological/historical sites high quality streams, wetlands, or other sensitive areas on the site . All mitigating conservation measures which are proposed to avoid or reduce adverse impacts from preparations of the site and construction activities should be described in the EID.

II.C.3. Transportation Impacts

In this section we will discuss, in some detail, the emissions of various transportation modes involved with coal gasification facilities.

II.C.3.a. Railroads. Railroads, diesel and electric powered, transport nearly 70% of all bituminous coal mined in the U.S.* Three types of trains are used in transporting raw coal:

- Conventional
- Unit
- Dedicated

When conventional trains are used, cars carrying coal are treated like any other car. Unit trains are made up entirely of cars carrying coal. When coal is transported by conventional trains, the Interstate Commerce Commission's (ICC) general rates apply. In contrast, a special rate of almost one third less applies to special unit trains.

Unit trains offer several other advantages including better use of equipment, elimination of standard railroad tie-ups such as classification yards and layover points, and promotion of better coordination between mine production and consumers, particularly consumers dependent on coal supplied by a single mine (National Academy of Engineering, 1974).

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*Although data for all coals are not available, bituminous coal represents all but a small fraction of coal mined.

Table 23. Outline of potential environmental impacts and relevant pollutants resulting from site preparation and construction practices.

Construction practice	Potential environmental impacts	Primary pollutants
1. Preconstruction		
a. Site inventory	Short term and nominal	Dust, noise, sediment
(1) Vehicular traffic	Dust, sediment, tree injury	
(2) Test pits	Tree root injury, sediment	
b. Environmental monitoring	Negligible if properly done	Visual
c. Temporary controls	Short term and nominal	Sediment spoil, nutrients, solid waste
(1) Sedimentation ponds	Vegetation destroyed, water quality improved	
(2) Dikes and berms	Vegetation destroyed, water quality improved	
(3) Vegetation	Fertilizers in excess	
(4) Dust control	Negligible if properly done	
2. Site Work		
a. Clearing and demolition	Short term	Dust, sediment, noise solid wastes, wood wastes
(1) Clearing	Decreased area of protective tree, shrub, ground covers; stripping of topsoil; increased soil erosion, sedimentation, stormwater runoff; increased stream water temperatures; modification of stream banks and channels, water quality	
(2) Demolition	Increased dust, noise, solid wastes	
b. Temporary facilities	Long term	Gases, odors, fumes particulates, dust, deicing chemicals, noise, petroleum products, wastewater, solid wastes, aerosols, pesticides
(1) Shops and storage sheds	Increased surface areas impervious to water infiltration, increased water runoff, petroleum products	
(2) Access roads and parking lots	Increased surface areas impervious to water infiltration, increased water runoff, generation of dust on unpaved areas	

(continued on next page)

Table 23. Outline of potential environmental impacts and relevant pollutants resulting from site preparation and construction practices (Continued).

Construction practice	Potential environmental impacts	Primary pollutants
(3) Utility trenches and backfills	Increased visual impacts, soil erosion, sedimentation for short periods	
(4) Sanitary facilities	Increased visual impacts, solid wastes	
(5) Fences	Barriers to animal migration	
(6) Laydown areas	Visual impacts, increased runoff	
(7) Concrete batch plant	Increased visual impacts; disposal of wastewater, increased dust and noise	
(8) Temporary and permanent pest control (termites, weeds, insects)	Nondegradable or slowly degradable pesticides are accumulated by plants and animals, then passed up the food chain to man. Degradable pesticides having short biological half-lives are preferred for use	
c. Earthwork	Long term	Dust, noise, sediment, debris, wood wastes, solid wastes, pesticides, particulates, bituminous products, soil conditioner chemicals
(1) Excavation (2) Grading (3) Trenching (4) Soil treatment	Stripping, soil stockpiling, and site grading; increased erosion, sedimentation, and runoff; soil compaction; increased in-soil levels of potentially hazardous materials; side effects on living plants and animals, and the incorporation of decomposition products into food chains, water quality	
d. Site drainage	Long term	Sediment
(1) Foundation drainage (2) Dewatering (3) Well points (4) Stream channel relocation	Decreased volume of underground water for short and long time periods, increased stream flow volumes and velocities, downstream damages, water quality	
e. Landscaping		Nutrients, pesticides
(1) Temporary seeding (2) Permanent seeding and sodding	Decreased soil erosion and overland flow of stormwater, stabilization of exposed cut and fill slopes, increased water infiltration and underground storage of water, minimized visual impacts	

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Table 23. Outline of potential environmental impacts and relevant pollutants resulting from site preparation and construction practices (Continued).

Construction practice	Potential environmental impacts	Primary pollutants
3. Permanent facilities		
a. Coal gasification plant and heavy traffic areas	Long term	Sediment, dust, noise, particulates
(1) Parking lots	Stormwater runoff, petroleum products	
(2) Switchyard	Visual impacts, sediment, runoff	
(3) Railroad spur line	Stormwater runoff and sedimentation	
b. Other buildings	Long term	Solid wastes
(1) Warehouses	Impervious surfaces, stormwater runoff, solid wastes, spillages	
(2) Sanitary waste treatment	Odors, discharges, bacteria, viruses	
c. Possible ancillary facilities	Long term	Sediment, trace elements, noise, caustic chemical wastes, spoil, flocculants, particulates, fumes, solid wastes, nutrients.
(1) Intake and discharge channel	Shoreline changes, bottom topography changes, fish migration, benthic fauna changes	
(2) Water supply and treatment	Waste discharges, water quality	
(3) Stormwater drainage	Sediment, water quality	
(4) Wastewater treatment	Sediment, water quality	
(5) Dams and impoundments	Dredging, shoreline erosion	
(6) Breakwaters, jetties, etc.	Circulation patterns in the waterway	
(7) Fuel handling equipment	Spillages, fire, and visual impacts	
(8) Seed storage areas and preparation facilities	Visual impacts, waste discharges	
(9) Oxygen plant and gas upgrading plant	Sediment runoff, landscape alteration, waste discharges	
(10) Cooling towers, power transmission lines, pipelines, substations	Visual impacts, sedimentation and erosion	

(continued on next page)

Table 23. Outline of potential environmental impacts and relevant pollutants resulting from site preparation and construction practices (Concluded).

Construction practice	Potential environmental impacts	Primary pollutants
(11) Conveying systems (cranes, hoists, chutes)	Visual impacts	
(12) Cooling lakes and ponds	Conversion of terrestrial and free flowing stream environment to a lake environment(land use trade-offs); hydrological changes, habitat changes, sedimentation, water quality	
(13) Solid waste handling equipment (incinerators, trash compactors)	Noise, visual impacts	Particulates, dust, solid wastes
d. Security fencing	Long term	Sediments, wood wastes
(1) Access road	Increased runoff	
(2) Fencing	Barriers to animal movements	

Source: Hittman Associates, Inc. 1974. General environmental guidelines for evaluating and reporting the effects of nuclear power plant site preparation, plant and transmission facility construction. Modified from: Atomic Industrial Forum, Inc. Washington DC.

The dedicated railroad, the third rail option, is used exclusively for transporting coal. A dedicated railroad generally is used only when an existing railroad is not available and when the railroad will link a mine to a single-source user.

II.C.3.b. Barges. Barges only move about 11% of the raw coal shipped in the U.S. (based on the fact that bituminous accounts for over 90% of all coal produced in the U.S.). In such areas as the Ohio River Valley, barges can be loaded directly from the mine. When mines are not located adjacent to a navigable river, the coal has to be transported to the barge loading facility by either truck or train (usually by train).

II.C.3.c. Trucks. Moving as much coal as barges do, trucks offer the major advantage of flexibility; their major disadvantage is a failure to be cost effective for moving large quantities long distances.

II.C.3.d. Pipelines. Slurry pipelines can be used to transport pulverized coal suspended in water. In this system, coal has to be processed to obtain the proper particle size. Pumping stations, dewatering facilities, and in some cases, storage facilities also are required. The major advantage of slurry pipelines for transporting coal long distances is low operating cost (Mutschler and others, 1973). High capital costs and water requirements are major disadvantages.

In terms of potential environmental impacts, four impact categories should be addressed in the EID (see Table 24 for an estimate of environmental residuals for six transporation technologies by region):

- Water
- Air
- Solids
- Land

1. Water - Barges may contribute dissolved solids to the river water. Drying the coal, after transporting via a slurry pipeline, produces a water effluent with negligible amounts of coal in it. Other modes of coal transportation do not involve water.
2. Air - Particulates, ranging from 1 to 46 tons per 10^{12} Btu's transported (Table 24), represent those associated with wind losses along the route and at the end points. A 2% wind loss is assumed for conventional trains as opposed to 1% for unit trains, river barges, and trucks. Based on these assumptions, transportation methods emit more particulates than any of the technologies in the coal development system. Other air emissions from transportation methods are due to diesel fuel combustion; thus, haul distances govern the magnitude of the total amounts emitted. In any case, the nitrous oxide and sulfur dioxide emissions are low, ranging from 0.5 to 4.3 tons and 0.1 to 4.4 tons, respectively, for each 10^{12} Btu's transported. Comparisons between transporation modes are meaningful because equal haul distances have not been assumed.
3. Solids - Solids arise from water and air emissions.

Table 24. Environmental and Health Impacts of Coal Transportation: By coal region and transportation mode

System	Air pollutants (tons/10^{12} Btu's)							$F/_{I}{}^{a}$	Occupational health 10^{12} Btu's		
	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids	Land acre-year/10^{12} Btu's	Deaths	Injuries	Man-days lost
Unit train											
Northwest coal	23.6	2.67	2.32	1.78	2.5	.392	NA	75.1/0 75.1	.075	.599	55.6
Central coal	20.3	4.17	3.7	2.85	3.99	.626	NA	30.4/0 30.4	.066	.876	81.3
Northern Applachian coal	18.4	4.28	3.71	2.85	4.	.627	NA	27.670 27.6	.065	.856	79.6
Central Appalachian coal	18.1	5.06	4.39	3.38	4.73	.743	NA	26.6/0 26.6	.062	.767	71.4
Southwest coal	20.9	1.59	1.38	1.06	1.49	.234	NA	67.2/0 67.2	.067	.0534	49.6
Mixed or conventional train											
Northwest coal	46.3	2.12	1.83	1.41	1.97	.31	NA	75.1/0 75.1	.075	.599	55.6
Central coal	38.9	3.42	2.96	2.28	3.18	.502	NA	30.4/0 30.4	.066	.876	81.3
Northern Appalachian coal	35.	3.4	2.94	2.27	3.17	.499	NA	27.6/0 27.6	.065	.856	79.6
Central Appalachian coal	33.8	2.89	2.51	1.93	2.7	.424	NA	26.6/0 26.6	.062	.767	71.4

(Continued next page)

Table 24. Residuals for the transportation of coal (Concluded)

	Air pollutants (tons/10^{12} Btu's)							$F/_I{}^a$	Occupational health 10^{12} Btu's		
System	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids	Land acre-year 10^{12} Btu's	Deaths	Injuries	Man-days lost
Slurry pipeline river barge											
Central coal	20.	.794	.85	.566	.67	.045	NA	NA	.0019	.0032	.243
Northern Appalachian coal	19.7	1.9	2.04	1.22	1.63	.095	NA	NA	.0019	.0032	.243
Central Appalachian coal	17.4	.689	.739	.443	.591	.034	NA	NA	.0019	.0032	.243
Trucking											
Northwest coal	22.9	1.69	.124	.169	1.03	.027	NA	0	.032	.692	45.4
Central coal	19.	1.4	.104	.14	.866	.023	NA	1.84/0 1.84	.032	.692	45.4
Northern Appalachian coal	17.	1.28	.093	.128	.776	.021	NA	1.67/0 1.67	.032	.692	45.4
Central Appalachian coal	16.4	1.29	.09	.124	1.754	.02	NA	1.6/0 1.6	.032	.692	45.4
Conveyor											
Central coal	0	NA	NA	NA	NA	NA	NA	.42/0 .42	0	0	0
Northern Appalachian coal	0	NA	NA	NA	NA	NA	NA	.386/0 .386	0	0	0
Central Appalachian coal	0	NA	NA	NA	NA	NA	NA	.376/0 .376	0	0	0

NA = Not applicable

[a] Fixed land requirement $(\frac{\text{acre-yr.}}{10^{12}\text{Btu}})$/Incremental land requirement $(\frac{\text{acres}}{10^{12}\text{Btu}})$

Source: University of Oklahoma, Science and Public Policy Program 1975

4. Land - The National Academy of Engineering (NAE) has pointed out that most new overland transportation systems will need additional rights-of-way and new facilities. Railroad land use requirements for coal transport are based on the percentage of coal to total rail freight and on the percentage of coal originating in the area. Because haul distances are not equal among the 6 transportation modes, values given in Table 24 are not directly comparable. Land use for coal transported ranges from 1 to 70 acres per 10^{12} Btu's transported. Of additional interest are the assumptions that rail rights-of-way averages 6 acres per mile (approximately 55 feet wide) a conveyor requires 30 feet of right-of-way along its length (3.64 acres per mile), and trucks average 1.67×10^{-6} acres per ton-mile (allow 50% error in the data) (University of Oklahoma, 1975).

II.D. MODELING OF IMPACTS

The ability to forecast environmental impacts accurately often is improved by the use of mathematical modeling of the dispersion and dissipation of air and water pollutants as well as the effects of storm runoff.

Two of the most widely used and accepted water quality models are:
- DOSAG (and its modifications)
- The QUAL series of models developed by the Texas Water Development Board and modified by Water Resources Engineers, Inc.

Some of the parameters that these models simulate are:
- Dissolved oxygen
- BOD
- Temperature
- pH
- Solids

In addition, there are many available water quality models that were developed in association with NPDES activity and the need for optimization of waste load schemes for an entire river basin.

There also are available mathematical models that may be used for air pollution studies:
- For short term dispersion modeling of point sources, EPA's PTMAX, VALLEY PTDIS, PTMTP and CRSTER models may be employed.
- For modeling of long term concentrations over larger areas, the EPA's Climatological Dispersion and AQDM models may be used for point and area sources.

In general, the use of mathematical models is indicated when arithmetic calculations are too repetitious or too complex. Their use also simplifies analysis of systems with intricate interaction of variables. Models thus offer a convenient way of describing the behavior of environmental systems, but their use and applicability should be determined on a case by case basis. (For a more detailed discussion of modeling techniques see section II.F., Modeling of impacts, in Environmental Impact Assessment Guidelines For New Source Fossil-Fueled Steam Electric Generating Stations.)

III. POLLUTION CONTROL

III.A. POLLUTION CONTROL TECHNOLOGY: IN PROCESS CONTROLS

Emissions can be reduced within the process through a variety of steps which should be examined carefully during project planning and described fully in the EID.

Principal methods to be considered to reduce effluents and emissions include:

- Use of process wastewater for cooling purposes
- Use of process wastewater for scrubbing purposes
- Recovery of sulfur from waste gases
- Recycling of waste gas
- Wetting and covering of coal storage and preparation areas.

III.B. POLLUTION CONTROL TECHNOLOGY: END OF PROCESS CONTROLS (EFFLUENTS FROM PROCESS)

The handling of the process and cooling water stream can represent one of the major pollution problems in an SNG plant. For economic and other reasons many gasification plants are seriously considering recycling all process water. The SNG plant water treatment systems have to be designed specifically for each plant. No one process will be universally applicable. The variety of coal sources and gasifier operating conditions differentiate the aqueous wastes in the various processes under development.

Water treatment technology, historically, has been divided into primary, secondary, and tertiary or advanced treatment. Primary treatment usually occurs first and is designed to remove much of the suspended solids and biochemical oxygen demand (BOD). The conventional operations in primary treatment, sometimes called clarification, are coagulation, flocculation, and sedimentation. Secondary or biochemical treatment oxidizes dissolved organic material to reduce BOD by about 90%. Tertiary or advanced treatment involves treatment of pollutants with lower BOD. The operations involved in this level of treatment have, in general, not been in operation commercially for over five years.

The Lurgi process is designed for zero water effluents. Thus, all potential contaminants that can be carried by the water are retained at the plant site. Approximately 80% of the total water make-up comes from the water supply source and only about 5% of the total water consumed leaves the plant as part of the wet ash and in the byproduct ammonia solution. Almost all of the organic byproducts are removed through the various process stages (some trace amounts remain). Finally, the soluble phenols fraction is removed during the Phenolsolvan process. Inorganic byproducts such as ammonia, hydrogen sulfide, and hydrogen cyanide are treated by stripping and oxidation in conventional sour water treatment processing schemes. Ammonia is steam stripped from the liquor and condensed as an aqueous solution of 24.1 percent by weight ammonia. This solution usually is stored and ultimately sold for its commercial value. Carbon dioxide and hydrogen sulfide also may be collected from a deacidifier column and sent through the Rectisol process to the sulfur recovery process.

It might be desirable to have additional storage capacity in the effluent water treatment system to provide hold-up in case of a process upset. There is danger that the levels of phenol or ammonia would be excessive for the biological activity. Another possible procedure for treatment of such a stream would be to use a tertiary water treatment technique, which should be available on a standby basis prior to mixing it into the normal biological oxidation feed stream. To optimize results, the feed stream composition to the biological oxidation units should be kept as constant as possible.

In the paragraphs that follow control technologies for specific pollutants are discussed.

III.B.1. Ammonia

Because no process water is released, water treatment methods necessarily relate to purifying water to process quality. The ammonia that is treated is residue remaining after byproduct ammonia has been removed from the gas liquor treatment using the sour water stripper (see below). Trace quantities of ammonia also may come from the American Petroleum Institute (API) separator and from the sanitary sewer sewage system into the effluent water treatment section. Approximately 100 ppm (mg/l) of ammonia come in as free ammonia and 950 ppm come in as fixed ammonia. The ammonia is treated first in an aeration/settling polishing unit. These units are part of the biological treatment system. The effluent from the system normally contains less than 5 ppm ammonia measured as amines and is sent back to the cooling tower sump.

The sour water stripper used to recover ammonia from process streams should be designed to treat certain feed impurities which could cause pollution problems. The major factor in obtaining proper stripper operation is the pH of the feed stream. Impurities such as Cl, oil, phenols, mercaptans, cyanides, thiocyanates, and polysulfides can affect stripper capacity and corrode the materials of construction as well as contaminate the products. Oil can cause reboiler fouling and foaming in the tower. If the oil is stripped with the H_2S it could produce a black sulfur product which has a low commercial value. Most of the other impurities are potentially corrosive to the materials of construction.

III.B.2 Phenols

The source of phenol in the water, like ammonia, is from the gas liquor treatment system. The residual concentration of phenol in the water depends on the efficiency of the Phenosolvan process. It is estimated that 500 ppm phenol enter the effluent water treatment section (biological degradation) and are processed through two stages of aeration and settling ponds. The effluent water contains less than 3 ppm of phenol which then is sent to the cooling tower sump.

III.B.3. Other Aqueous Pollutants

Other aqueous pollutants that are treated by the biological treatment system include BOD_5 and suspended solids. The BOD concentration which often is

2,500 ppm is reduced to 75 ppm. Suspended solids which are negligible in the inlet stream increase to about 5 ppm. As mentioned previously, the effluent stream from the biological treatment system (effluent water treatment) is sent to the cooling tower sump.

Pollutants not accounted for quantitatively in the water phase include hydrogen cyanide (HCN) and hydrogen fluoride (HF). The quantities of hydrogen cyanide that are expected to be produced in coal gasification depend on temperature and pressure during gasification. During the Lurgi gasification process, some HCN is expected to be produced and can pass through the SNG system; it also may come in contact with water. Data on coal gasification processes indicate that much less than 1% of the coal nitrogen is converted to HCN. It appears that HCN is produced by the secondary reaction of ammonia with carbon in the reactor. It has been shown that HCN formation is a function of ammonia, partial pressure, contact time, and pressure. Increased partial pressure of steam can suppress production of HCN. Hydrogen cyanide, like hydrogen sulfide, may be removed in the Stretford or other sulfur recovery processes; however, quantities of these compounds may be contained in the water stream. If so, they might have to be treated separately because they can be detrimental to biological activity of the effluent water treatment system, especially if concentrations fluctuate.

Hydrogen fluoride, because of its high reactivity, is expected to react with the calcium oxide, silica, or alumina in ash and ultimately to be disposed of with the ash. Hydrogen fluoride that may enter the water stream can be neutralized by basic minerals that also are present, or calcium oxide can be added for purposes of neutralization.

Undoubtedly, coal pile runoff and coal dust will enter the wastewater stream. Runoff from the coal pile as well as dust which is washed in water sprays from the screening operations may be transported in the water stream and may ultimately enter the evaporation pond. Modifications to reduce coal pile runoff wastes include the design of storage areas which will minimize the area subject to rainfall by diverting runoff from other areas away from the coal pile and the covering of inactive coal storage areas.

The water stream also may contain traces of organic materials that are carcinogenic and which are not readily removed by biological treatment. (About 90% of the total organic carbon is removed by biological action.) These materials could enter the environment, for example, in the form of a water spray from cooling towers.

Other sources of aqueous pollution such as the chemicals used for regenerating the demineralizers system often can end up in the ash quench and removal section and ultimately be returned to the mine. The resulting slurry, however, still may contain leachable materials. Some solid materials and solid inorganic compounds also may enter the effluent water stream from the sulfur recovery process through leakage. Quantities normally are small but disposal may present problems. The applicant, therefore, should evaluate and discuss all proposed treatment and disposal plans in the EID. At a minimum, the applicant should demonstrate:

- That the proposed treatment scheme is capable of eliminating or reducing potential water pollution problems
- The nature and efficacy of the proposed treatment scheme
- The efficacy of the treatment scheme for specific principal pollutants such as phenols, NH_3, HCN, and H_2S
- The quality of and sink for the principal waste steams after treatment.

III.C. POLLUTION CONTROL TECHNOLOGY: END OF PROCESS CONTROLS (EMISSIONS)

Emissions from several of the processes in the coal gasification operation will require control. In some cases, control equipment will be needed, whereas in others sufficient control can be achieved by careful operation or process modification. Control of emissions from the principal sources is discussed below.

III.C.1. Coal Storage and Preparation

Generation of dust and coal fines from coal storage piles can be reduced significantly by wetting. Conveyors also should be covered to contain particulate emissions. Coal crushing and drying should be performed in enclosed spaces at slightly negative pressure; the exhaust emissions should be cleaned by bag filters.

III.C.2. Gasification Processes

Although there are no major atmospheric emission streams, careful handling of dry ash and char is necessary to prevent particulate emissions, and quench systems for ash and char should be designed to prevent odors.

III.C.3. Acid Gas Removal

Potential atmospheric emissions of harmful sulfur compounds can be reduced or rendered less harmful by combustion to SO_2 or conversion to sulfur.

III.C.4. Sulfur Recovery

Coal gasification plants produce a large quantity of waste gas which contains sulfur compounds (primarily H_2S). This waste gas must, therefore, be treated for sulfur removal before release to the atmosphere. Both rich and lean sulfur waste gas streams are produced in many designs and each requires a different method of treatment.

The Claus sulfur recovery process generally is used to remove sulfur from the rich gas stream. Claus plant tail gas requires further treatment because sulfur recovery efficiency is only about 95%. This tail gas may be burned to convert the H_2S to SO_2. However, combustion may be expensive because of auxiliary fuel requirements due to the high CO_2 concentration which reduces the heating value of the gas and because the high resultant SO_2 emissions may require scrubbing. Alternatively, this tail gas can be treated for further sulfur recovery in an advanced process, such as Beavon, Cleanair, or IFP process, in which 99.5%-99.9% of the sulfur can be removed. This type of tail gas treatment also may be expensive.

For this gas, liquid phase sulfur recovery may be used to remove the H_2S. Liquid phase sulfur recovery achieves almost complete conversion of H_2S to elemental sulfur but does not remove other reduced sulfur compounds. Thus, the waste gas may require further treatment such as combustion to convert the sulfur compounds to SO_2.

The Stretford process, which has been described earlier, is primarily a wet process for the recovery and/or removal of sulfur and air pollutant emissions including COS and CS_2 and hydrocarbons.

III.C.5. Briquetting

Because the Lurgi process requires a relatively uniform coal particle, briquetting of the fines may be necessary. If this is so, a bake oven may be used and therefore, it also must be controlled. An afterburner is an appropriate control technique that should be considered by the permit applicant.

III.D. POLLUTION CONTROL TECHNOLOGY: END OF PROCESS CONTROLS (SOLID WASTE DISPOSAL)

Four major types of solid wastes requiring disposal could be generated at a coal gasification facility:

- Ash from the gasifiers, evaporator residue, and fly ash from steam boilers
- Inorganic sludge and silt from raw water treatment
- Sludge from biological treatment unit for sanitary sewage
- Refuse (e.g., paper, cartons, rags, wood scraps, etc.).

Ash is the principal solid waste that must be disposed of by a coal gasification facility. Quantities of ash may range from 3,500 to 8,500 tons/10^{12} Btu's of coal processed. The amount and nature of the material usually discourage any disposal method other than land disposal. Because any leachate is probably contaminated, leaching must be prevented or the leachate must be treated by neutralization, metals precipitation, settling and biological oxidation. The ash from many coals will solidify when mixed with small amounts of water; this characteristic has been used to reduce leaching problems. It has been suggested that alkaline ash be disposed of in abandoned coal mines that have acid-leachate problems; however, normally the ash is dewatered in the ash handling facilities and then returned to the mine. Residues from evaporators and the inorganic sludge and silt from raw water treatment also could be disposed of at the mine with the ash. Sludge from a biological wastewater treatment plant can be returned to the mine or used as a soil conditioner. Also when evaporation ponds are used, they produce a solid waste that can contain a number of undesirable components, primarily metals. Therefore, it is important to cover or seal these ponds after pond operation is discontinued to prevent leaching. Refuse should be burned in an incinerator to prevent potentially dangerous leachates from entering ground water supplies.

IV. OTHER CONTROLLABLE IMPACTS

IV.A. AESTHETICS

New source coal gasification facilities may be large and complex facilities occupying an area of up to several hundred acres. Coal storage and handling areas, air emission stacks, and other plant components may approach significant heights above the ground. Particularly in rural and suburban areas, this configuration represents a noticeable intrusion on the landscape; existing industrial areas would be less affected. Measures to minimize the impact on the environment must be developed during site selection and design. The applicant should consider, as applicable, the following factors to reduce potential aesthetic impacts:

- Existing Nature of the Area: The topography and major land uses in the area of the candidate sites are important. Topographic conditions, such as hills, can be used to screen the plant from view. A lack of topographic relief will require other means of minimizing impact, such as regrading or vegetation buffers. Analysis of major land uses may be useful to assist in the design and visual appearance of the facility. The design of the facility should reflect, to the extent practical, the nature of the area in which it is to be placed. The use of artists' conception, in the EID, preferably in color, will be most useful in determining the visual impact and appropriate mitigation measures.
- Proximity of Sites to Parks and Other Areas Where People Congregate for Recreation and Other Activities: The location of these areas should be mapped and presented in the EID. Representative views of the plant (site) from observation points should be described. The visual effects on these recreational areas should be described in the EIA in order to develop the appropriate mitigation measures.
- Transportation System: The visual impact of new access roads, raillines, pipelines, etc., on the landscape should be considered. Locations, construction methods and materials, and maintenance should be specified.
- Creation of Aesthetically Pleasing Areas: If planned carefully, the development of a coal gasification complex can create aesthetically pleasing areas. Screening the facility by vegetation may improve the appearance of an area. Construction of a cooling lake, and the development of recreational facilities and open space also may be an improvement to the area. Such positive impacts should be presented in the EID.

IV.B. NOISE

The major sources of noise associated with a coal gasification plant are:

- Coal transportation system (railroad)
- Coal preparation facilities (crushers and screens)
- Coal boxes
- Oxygen generation facilities
- Flare values, steam values, steam releases.

Ordinarily a coal gasification plant will not create significant ambient noise levels during plant construction and operation.

The methodology to evaluate noise generated from a proposed coal gasification plant would require that the applicant:

- Identify all noise-sensitive land uses and activities adjoining the proposed site
- Measure the existing ambient noise levels of the areas adjoining the site
- Identify existing noise sources, such as traffic, aircraft flyover, and other industry, in the general area
- Determine whether there are any State or local noise regulations that apply to the site
- Calculate the noise level of the gasification plant in operation and compare with the existing community noise levels and the applicable noise regulations
- Calculate the change in community noise levels resulting from construction of the gasification facility
- Assess the noise impact of the plant's operational noise and construction noise, and, if required, determine noise abatement measures to minimize the impact (quieter equipment, noise barriers, improved maintenance schedules, etc.)

IV.C. SOCIOECONOMIC

The introduction of a large new coal gasification facility into a community may cause economic and social changes. Therefore, it is necessary for an applicant to understand the types of impacts or changes that may occur so that they can be evaluated adequately. The importance of these changes usually depends on the nature of the area where the plant is located (e.g., size of existing community). Normally, however, the significance of the changes caused by a plant of a given size will be greater in a small, rural community than in a large, urban area. This is primarily because a small, rural community is likely to have a nonmanufacturing economic base and a lower per capita income, fewer social groups, a more limited socioeconomic infrastructure, and fewer leisure pursuits than a large, urban area. There are situations, however, in which the changes in a small community may not be significant and, conversely, in which they may be considerable in an urban area. For example, a small community may have had a manufacturing (or natural resource) economic base that has declined. As a result, such a community may have a high incidence of unemployment in a skilled labor force and a surplus of housing. Conversely, a rapidly growing urban area may be severely strained if a new coal gasification plant is located there.

The rate at which the changes occur (regardless of the circumstances) also is an important determinant of the significance of the changes. The applicant should distinguish clearly between those changes occasioned by the construction of the plant and those resulting from its operation. The former changes could be substantial but usually are temporary; the latter may or may not be substantial but normally are more permanent in nature.

During the construction phase, the impact will be greater if the project requires large numbers of construction workers to be brought in from outside the community than if local, unemployed workers are available. The impacts are well known and include:

- Creation of social tension
- Demand for increased housing, police and fire protection, public utilities, medical facilities, recreational facilities, and other public services
- Strained economic budget in the community where existing infrastructure becomes inadequate.

Various methods of reducing the strain on the budget of the local community during the construction phase should be explored. For example, the company itself may build the housing and recreation facilities and provide the utility services and medical facilities for its imported construction force; or the company may prepay taxes and the community may agree to a corresponding reduction in the property taxes paid later. Alternatively, the community may float a bond issue, taking advantage of its tax-exempt status, and the company may agree to reimburse the community as payments of principal and interest become due.

During plant operation, the more extreme adverse changes of the construction phase are likely to disappear. Longer run changes may be profound, but less extreme, because they evolve over a longer period of time and may be both beneficial and harmful.

The permit applicant should document fully in the EID the range of potential impacts that are expected and demonstrate how possible harmful changes will be handled. For example, an increased tax base generally is regarded as a positive impact. The revenue from it usually is adequate to support the additional infrastructure required as the operating employees and their families move into the community. The spending and respending of the earnings of these employees has a multiplier effect on the local economy, as do the interindustry links created by the new plant. Socially, the community may benefit as the increased tax base permits the provision of more diverse and higher quality services and the variety of its interests increases with growth in population. Contrastingly, the transformation of a small, quiet community into a larger, busier community may be regarded as an adverse change by some of the residents, who chose to live in the community, as well as by those who grew up there and stayed, because of its amenities. The applicant also should consider the economic repercussions if, for example, the quality of the air and water declines as a result of various waste streams from the coal gasification plant and its ancillary facilities.

In brief, the applicant's framework for analyzing the socioeconomic impacts of constructing and operating a coal gasification plant must be comprehensive. Most of the changes described should be measured to assess fully the potential costs and benefits. The applicant should distinguish clearly between the short term (construction) and long term (operation) changes, although some changes may be common to both (e.g., the provision of infrastructure) because the significance of the changes depends not only on their absolute magnitude but on the rate at which they occur.

The applicant should develop and maintain close coordination with State, regional, and local planning and zoning authorities to ensure full understanding with all existing and/or proposed land use plans and other related regulations.

IV.D. ENERGY SUPPLY

The impact of a coal gasification plant on local energy supplies will depend largely on the type of gasification process proposed and the ancillary facilities. If an oxygen separation unit is associated with the plant then the energy demand will increase significantly. The applicant should evaluate the energy efficiencies of all processes considered during project planning and then consider the alternative analysis. Also feasible design modifications should be considered in order to reduce energy needs. There are a number of processes that are exothermic and the applicant should evaluate the potential for using this waste heat to satisfy various energy demands within the plant, for example, steam for process purposes.

At a minimum, the applicant should provide the following information:

- Total external energy demand for operation of the plant
- Total energy generated on site
- Energy demands by type
- Proposed measures to reduce energy demand and increase plant efficiency

IV.E. IMPACT AREAS NOT SPECIFIC TO COAL GASIFICATION

The intent of the preceding sections was to provide guidance to new source NPDES permit applicants on those impact areas that are specific to or representative of coal gasification facilities. It is recognized that many impacts resulting from the construction and operation of a coal gasification plant are similar to impacts associated with many other new source facilities; therefore, no effort has been made to discuss these types of impacts, but, instead, to reference other more general guideline documents. For example, general guidelines for developing a comprehensive inventory of baseline data (preproject conditions) and a methodology for impact evaluation are contained in Chapters 1 and 2 of the EPA document, Environmental Impact Assessment Guidelines for Selected New Source Industries. Although broad in scope, this document and other appropriate guidance materials should be used by the applicant for assistance in evaluating non-industry-specific impacts.

V. EVALUATION OF AVAILABLE ALTERNATIVES

V.A. SITE ALTERNATIVES

Preliminary site selection studies should take place before the EID document is prepared. These studies should include a thorough analysis of all feasible site locations. This identification and analyses of sites should be described in the EIA, and the reasons for eliminating a site(s) should be specified. Adequate information on all feasible site alternatives is a necessary consideration in issuing, conditioning, or denying an NPDES permit .

Several different agencies may be able to offer assistance in evaluating potential areas for location of a coal gasification facility.

- State, regional, county, or local zoning or planning commissions can describe their land use programs and where variances are required. Federal lands are under the authority of the appropriate Federal land management agency (Bureau of Reclamation, U.S. Forest Service, National Park Service, etc.).
- State or regional water resource agencies can provide information relative to water appropriations and water rights.
- Air pollution control agencies can provide assistance relative to air quality allotments and other air-related standards and regulations.
- The Soil Conservation Service and State Geological Surveys can provide data and consultation on soil conditions and geologic characteristics.

In the EID the applicant should display the potential site locations on maps that show environmental conditions and other relevant site information. (A consistent identification system for the alternative sites should be established and retained on all graphic and verbal material.) Such may include but not be limited to:

- Areas and sites considered by the applicant
- Major centers of population density (urban, high, medium, low density or similar scale)
- Water bodies suitable for water use and cooling
- Railways, highways (existing and planned), and waterways suitable for the transportation of raw materials, byproducts, and wastes
- Important topographic features (such as mountains and marshes)
- Dedicated land-use areas (parks, historic sites, wilderness areas, testing grounds, airports, etc.)
- Other sensitive environmental areas
- Existing power generating station(s), if any, with total transport of high Btu gas
- Industrial complexes, significant mineral deposits, and mineral industries.

Using these graphic materials, the applicant should provide a condensed description of the major considerations that led to the selection of the final candiate sites, including proximity to raw materials, adequacy of transportation systems, economic analyses with tradeoffs, environmental considerations, license or permit problems, compatibility with any existing land use planning programs, and current attitudes of interested citizens.

Having discussed candidate sites, the applicant also should indicate the steps, factors, and criteria used to select the proposed site. The applicant should present a cost-effectiveness analysis including pertinent environmental social, and economic considerations to show why the proposed site plant combination is preferred over all other candidate site alternatives proposed facility. Economic estimates should be based on an at least preliminary conceptual design that considers how construction costs are affected by site-related factors.

Quantification, although desirable, may not be possible for all factors because of lack of adequate data. Under such circumstances, qualitative and general comparative statements, supported by documentation, may be used. Where possible, experience derived from operation of other industrial facilities at the same site, or at an environmentally similar site, may be helpful in appraising the nature of expected environmental impacts.

Therefore, if the proposed site location proves undesirable, then alternative sites from among those originally considered should be reevaluated or new sites should be identified and evaluated. Expansion or technological changes at an existing plant site may be a possible alternative. Therefore, it is critical that a permit applicant systematically identify and assess all feasible alternative site locations as early in the planning process as possible.

V.B. ALTERNATIVE PROCESSES, DESIGNS, AND OPERATIONS

All feasible process alternatives should be evaluated carefully on the basis of reliability, economy, and engineering factors.

V.B.1. Other Coal Gasification Processes

To date, commercially proven technology for the gasification of coal has been demonstrated by Lurgi, Koppers-Totzek, and Winkler processes. There is, as described in section I.B., a variety of other coal gasification processes which should be considered. Those process alternatives that appear practical should be screened further on the basis of, at least, the following factors:

- Land requirements, raw material, waste treatment, and storage requirements
- Release to air of dust, sulfur dioxide, nitrogen oxides, and other potential pollutants, subject to Federal, State, or local limitations
- Releases to water of heat, chemicals, trace metals, and other constituents subject to Federal, State, and local regulations
- Water consumption rate
- Fuel consumption and the generation of ash with associated waste disposal
- Reliability and energy efficiency
- Economics
- Aesthetic considerations for each alternative process.

A tabular or matrix form of display often is helpful in comparing the feasible alternatives. Alternative processes which are not feasible should be dismissed with an objective explanation of the reasons for rejection.

V.B.2. Alternative Systems Within the Process

The principal unit systems in a gasification process (e.g., Lurgi) are:

- Gasification
- Gas shift conversion
- Gas cooling
- Rectisol
- Phenosolvan
- Methanation
- Gas liquor separation

The applicant should investigate all feasible alternative methods available for each of these unit systems. The selected coal gasification process should incorporate an efficient combination of component systems which have been selected through a systematic analysis of economic, environmental, and engineering factors. The applicant also should present the major determining factor(s) for negative or positive decisions. Economic comparisons should include initial capital costs and operating costs of the individual systems. All potential environmental impacts should be documented and qualified and the magnitude of the effects should be quantified wherever possible. Engineering comparisons must include the projected length of time the alternative systems would be operable. Estimated maintenance costs over the useful life of each system should be included, as should an analysis of the effect of maintenance on overall process efficiency and performance. The applicant also should present the major determining factor(s) for negative or positive decisions.

A similar analysis should be made for the ammonia recovery and sulfur conversion systems.

All systems that are considered should be described in the EID as well as the specific criteria used for decision-making. For each alternative, the applicant also should present the major determining factor(s) for negative or positive decisions.

V.C. NO-BUILD ALTERNATIVE

In all proposals for facilities development, the applicant must consider and evaluate the impact of not constructing the proposed new source facility. Because this analysis is not unique to the development of a coal gasification facility, no specific guidance is provided as part of this appendix. The permit applicant, therefore, is referred to Chapter IV (Alternatives to the Proposed New Source) in the EPA document, Environmental Impact Assessment Guidelines for Selected New Source Industries, which was published in October 1975.

VI. REGULATIONS (OTHER THAN POLLUTION CONTROL)

The applicant should be aware that there may be a number of regulations other than pollution control regulations that may apply to the siting and operation of new coal gasification facilities. The applicant should consult with the appropriate EPA responsible official regarding applicability of such regulations to the proposed new source. Federal regulations that may be pertinent to a proposed facility are:

Coastal Zone Management Act of 1972 (16 USC 1451 et seq.)
The Fish and Wildlife Coordination Act of 1974 (16 USC 661-666)
The National Environmental Policy Act of 1969 (42 USC 4321 et seq.)
USDA Agriculture Conservation Service Watershed Memorandum 108 (1971)
Wild and Scenic Rivers Act of 1969 (16 USC 1274 et seq.)
The Flood Control Act of 1944
Federal-Aid Highway Act, as amended (1970)
The Wilderness Act of 1964
Endangered Species Preservation Act, as amended (1973) (16 USC 1531 et seq.)
The National Historical Preservation Act of 1966 (16 USC 470 et seq.)
Executive Order 11593
Archaeological and Historic Preservation Act of 1974 (16 USC 469 et seq.)
Procedures of the Council on Historic Preservation (1973) (39 FR 3367)
Occupational Safety and Health Act of 1970

In connection with these regulations, the applicant should place particular emphasis on obtaining the services of a recognized archaeologist to determine the potential for disturbance of an archaeological site, such as an early Indian settlement or a prehistoric site. The National Register of Historic Places also should be consulted for historic sites such as battlefields.

The applicant should consult the appropriate wildlife agency (State and Federal) to ascertain that the natural habitat of a threatened or endangered species will not be adversely affected.

From a health and safety standpoint, all complex industrial operations involve a variety of potential hazards and to the extent that these hazards could affect the health of plant employees, they may be characterized as potential environmental impacts. These hazards exist in coal gasification plants because of the very nature of the operation (e.g., processing conditions which require high temperatures and pressures). All plant operators should emphasize that no phase of operation or administration is of greater importance than safety and accident prevention. Company policy should provide and maintain safe and healthful conditions for its employees and establish operating practices that will result in safe working conditions and efficient operation.

The plant must be designed and operated in compliance with the standards of the US Department of Labor, the Occupational Safety and Health Administration, and the appropriate State statutes relative to industrial safety. The applicant also should coordinate closely with local and/or regional planning and zoning commissions to determine possible building or land use restrictions.

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